

CRITICAL ISSUES IN ELECTRIC POWER PLANNING IN THE 1990s

EXECUTIVE SUMMARY

K. Morgan MacRae

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**CANADIAN
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K. MORGAN MACRAE

Critical Issues in Electric Power Planning
in the 1990s Executive Summary

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Preface

This project was a joint undertaking of the Canadian Energy Research Institute (CERI) and the Policy Studies Group of the Energy Policy Sector of Energy, Mines and Resources Canada. The project was conceived to address the myriad of important and, at times, controversial issues contributing to a period of significant change and uncertainty in the Canadian electricity industry.

CERI would like to thank the Policy Studies Group for their participation and acknowledge the following contributions. Sonia L'Heureux, Baxter MacDonald and James Stanford researched and wrote the provincial electricity vignettes contained in Volume II of this report. James Stanford was responsible for Chapter 2 on future capacity additions in the Canadian electricity industry and authored the historical overview of the industry contained in Volume II. Sonia L'Heureux co-authored Chapter 4, dealing with non-utility generation; Baxter MacDonald co-authored Chapter 6, dealing with the environmental constraints that will strongly influence utility planning decisions in the 1990s. Paul-André Rochon and Nik Marty of the Policy Studies Group assisted CERI in the design and management of the study.

Two other organizations made significant contributions to CERI's research. I would like to acknowledge the valuable work undertaken by Dr. Adrienne Kwaczek, formerly of the Alberta Energy Resources Conservation Board (ERCB) on regulatory developments in the United States (Volume II). Thanks is also due to the Alberta Research Council and, in particular, the contributions of Drs. Don Quon and Sam Wong who developed a model for CERI to assess future electricity supply, demand and trade patterns. Also acknowledged is the assistance of Mr. B. Emmett, formerly with Energy, Mines and Resources Canada and Dr. P. Prince (ERCB) for their assistance in arranging staff support from these organizations for this project.

The many individuals who served on the Advisory Committee to this study also contributed in a major way and their support and advice is gratefully acknowledged. As with all CERI research projects, the Advisory Committee offered their insight and constructive criticism on the draft report. The Advisory Committee was composed of

experts from 15 organizations representing industry, government, and academia in Canada, the United States and abroad.

Special thanks are due to a number of the Institute's staff: Janice Morrison and Beverly Kovacs, who processed the interim drafts and final manuscript; Megan Murphy, who created the graphics; and Zaytoon Janjua and Wendy Faid of the I.N. McKinnon Memorial Library, who gathered source materials from across the continent. Finally, my thanks to my colleague, Tony Reinsch, for his careful review and insightful comments.

This study brings together historical and current information on Canada's electric power system. An historical overview of Canadian electric power and the provincial vignettes contained in Volume II provide the context for Volume I where we discuss important issues facing Canadian electric power planning. This report specifically analyzes the current and prospective importance of a number of key issues, any one of which would be worthy of a detailed, book-length inquiry. To discuss all of these topics together required that the analysis be succinct and, at times, somewhat abbreviated.

The Institute hopes that you find this research study of interest, and that it addresses issues of specific importance. CERI is undertaking further analyses on Canadian electric power and to ensure the most pertinent research, we encourage your continued support, views and commentary.

EXECUTIVE SUMMARY

Introduction

Electric utilities in several Canadian provinces face an increasingly tight supply/demand balance. The excess generating capacity experienced in many provinces over the past decade has been gradually worked off, requiring a number of utilities to once again face the need to make significant additions to their resource base.

This need for new electrical generating capacity has important political, economic and social implications for Canada's electricity industry, including environmental protection, electricity trade, demand-side management and non-utility power production. The manner in which Canadian utilities will resolve each of these issues will depend, in large part, on the rate at which they must add new capacity.

Provinces facing moderate pressure for new supply have greater flexibility and more time to increase generating capacity and address socio-political issues such as environmental protection. Utilities with inadequate generating facilities to meet expected future demand will have to address these structural and policy issues in a more hurried fashion.

Canadian utilities have traditionally followed a self-reliant, demand-driven strategy to manage the supply/demand balance in each province and to provide the lowest cost power to customers. A utility would forecast future provincial demand, take this forecast and an associated range of uncertainty as a given, and construct sufficient capacity to meet expected demand. Demand in the utility's load area would be met almost exclusively with the utility's own generating facilities. In the past, low production costs from large-scale central generating facilities meant that little effort was made to encourage independent power production, or to supplement domestic generating capacity with firm imported power. Similarly, utilities did not take a proactive role in managing electricity demand, but simply accepted their duty as one of supplying whatever demand existed within their service area, subject to the prevailing price structure and regulatory regime.

This traditional approach to planning is undergoing substantial change. Utilities will increasingly rely on external resources (either imported power or non-utility generation) to help meet domestic demand. Likewise, interventionist demand management practices, designed to encourage more efficient load structures and consumption practices, will also become prevalent.

The pressures for new approaches to utility planning have been made feasible by changes in the economics of electricity generation, by changes in technology and by increasing public concern for environmental protection. It is to be expected that the attitudes and policies of the utilities and the structures of regulation which govern them will lag somewhat in adjusting to this new business environment. Nevertheless, it is the purpose of this study to attempt to identify and quantify, where possible, the potential benefits of new approaches to electricity planning, and to propose measures to help realize these benefits.

Many of these new strategies are in their infancy and the economic and regulatory conditions which will shape them have yet to be fully analyzed and understood. For the most part, the existing demand forecasts and electricity generation plans of Canadian utilities do not account for expected policy changes in the areas of trade, demand management, independent power production or environmental protection.

Future capacity additions in each province will depend on how Canadian utilities and their regulators respond to the growing interest in alternative approaches to the planning of future electricity supply and end use.

The Uncertainty of Electricity Demand

Electricity demand in Canada is being pulled by two competing forces. In one direction, Canada's economy has become more *energy efficient* in recent years. On average, this tends to reduce the total amount of energy required for a given amount of human activity. This tendency will likely continue, motivated by economic, environmental and technological forces.

Canada's economy, on the other hand, has become more *electricity intensive*. Electricity now accounts for almost 25 percent of all energy use in Canada, as opposed to just 18 percent only 10 years ago. An estimated 80 percent of electricity demand growth over this

period was the result of the substitution of electricity for other fuels. Only 20 percent was the result of expansion of Canadian demand for energy. While new technology promotes energy efficiency in almost all cases, in many circumstances it also contributes to growth in electricity intensity. It is far from apparent which force will exert the more decisive impact on Canada's electricity industry in the coming decade.

The aggregate electricity demand faced by Canadian utilities is ultimately composed of a wide variety of individual final uses in different sectors of the economy. These uses, in turn, are subject to a complex set of factors ranging from population growth and the expanding and changing structure of Canada's economy, to the certain but unpredictable course of technological change.

An important part of the challenge facing utility planners in the 1990s is to reduce the uncertainty derived from the complex nature of electricity demand by gathering more accurate and timely demand information and by improving forecasting techniques. The challenge extends to better understanding the nature of uncertainty, and *incorporating* this understanding directly into the planning process.

The future planning strategies of utilities will, for example, require increased efforts to maximize the *flexibility* of electricity supply to respond to unexpected demand developments. This could include an attempt to reduce the time-lag between the decision to proceed with a new capacity addition and its in-service date by streamlining the regulatory and planning processes. Another option is to utilize less capital-intensive generating facilities such as combined cycle plants or natural gas-fired units which take less time to construct than large hydroelectric stations and nuclear power plants. Alternatively, utilities may use electricity trade to deal with unplanned demand changes, either by selling surplus power to external customers in the event of a demand downturn, or calling back firm exports to supply the domestic market.

Key Findings

Capacity Additions

The amount of new generating capacity required by Canadian utilities through the rest of this century will surpass that experienced during the last decade. Depending on the demand forecast that is accepted, annual new capacity requirements may be greater than at any time in Canadian history.

The rate of capacity addition is very sensitive to assumptions regarding domestic demand growth. For example, total capacity additions required by the year 2000 in the high demand scenario developed for this study (3.5 percent average annual growth) are more than double those in the base scenario (2.4 percent average annual growth).

In the base case demand scenario, a total of just under 9300 MW of new capacity is required by the end of the century for Canada as a whole. This is in addition to the 14 500 MW of capacity that will be brought on-stream from committed projects, resulting in total capacity additions of just over 23 700 MW. On a province-by-province basis, the largest amount of uncommitted capacity will be required in Alberta. That province's fast-growing and energy-intensive industrial sector is the primary factor behind this large capacity requirement.

Quebec also faces the prospect of large uncommitted additions to its generating resources. As well, Quebec has more committed generation capacity under construction than any other province. In a number of provinces, including Manitoba and British Columbia, expected demand growth can be met on the basis of existing and committed projects alone, with no need to complete the construction of additional generation projects before the end of the century.

In the high demand scenario, the amount of required uncommitted capacity more than doubles, from just under 9300 MW in the base scenario to just under 23 000 MW. Combined with the 14 500 MW that will be brought on-stream from committed expansion projects, this results in a total estimate of new capacity additions of over 37 200 MW by the end of the century.

Quebec will require by far the most new generating capacity by the end of the century. Other provinces with major uncommitted capacity requirements include Alberta, New Brunswick, Nova Scotia and Saskatchewan. Ontario requires uncommitted capacity only in the high demand scenario; otherwise, committed capacity is sufficient to meet domestic demand until the year 2000 assuming that demand management and non-utility generation targets are successful.

The construction decision dates facing each province are currently uncertain and vary greatly with the assumptions made regarding future demand growth, size and timing of firm exports, and the type of fuel chosen for new facilities. Based on domestic demand requirements alone, British Columbia, Manitoba and New Brunswick

can wait until the mid-1990s before committing to the construction of new facilities. Canada's other provinces will need to decide on new capacity additions early in the 1990s.

Firm export projects further complicate the planning process for those provinces considering entry to firm power markets. Quebec and New Brunswick would need to commit to new construction projects immediately if they are to proceed with planned firm exports. British Columbia and Manitoba will need to decide on additional hydroelectric projects much sooner than would have been the case without the firm power export contracts (although in B.C.'s case, the option of coal-fired export plants, with their shorter construction periods, considerably stretches out the decision period). In Nova Scotia and Newfoundland, firm exports would be generated in export-dedicated facilities that can be considered more-or-less separate from the rest of their systems. These two provinces therefore face two sets of decision dates: one for domestic service facilities (needed relatively urgently) and one for export plants.

The fuel mix of future capacity additions is likely to remain similar to the existing resource base, with hydroelectric facilities accounting for some 60 percent of all new capacity. The share of nuclear power will increase slightly by the year 2000, offsetting a fall in oil and gas-fired capacity. The share of coal-fired plants will remain virtually constant. Those general trends are, of course, dependent on Canada's response to rising concern with the environmental impact of fossil-fuel combustion.

It must be stressed that this study focuses on a sensitivity analysis of demand and the potential implications. The figures presented are not a *forecast* of the size and timing of future capacity additions in Canada. We have not attempted to select one particular demand scenario, nor to determine which export projects are likely to come to fruition. However, our sensitivity analysis yields important, if tentative, findings.

If demand grows at the rate presently forecast by utilities, we expect a requirement for some 9000 MW of additional, as yet uncommitted capacity by the year 2000. If demand grows at rates consistent with the high demand scenario, capacity requirements more than double. And if the various firm export proposals being pursued by several provinces come to fruition, the need for new capacity is both increased and is more imminent. In all of the scenarios that were developed, the rate of construction of new capacity in Canada is

considerably greater than that experienced in the past decade. This will make it even more imperative that utilities and policymakers resolve fundamental issues that currently complicate the planning process--questions pertaining to environment, electricity trade, non-utility generation and demand-side management.

Demand Management

The risks associated with forecasting and planning for new electrical generating capacity have led some utilities to actively consider demand-side management (DSM) programs. DSM includes actions to improve system load factor and thereby reduce capital expenditures, improve capacity limitations, reduce the cost of service, and improve system efficiency and system reliability. Once a program infrastructure is in place, DSM enhances planning flexibility, as it requires comparatively short lead times for scaling the programs up or down as conditions dictate. Flexibility, safety, social concerns and environmental impacts are additional factors motivating some utilities and their regulators to support DSM programs.

Recent recommendations and research are indicative of DSM's evolution and increasing importance. Many DSM programs, however, are only in the conceptual and development stage and it will take time before their effects and costs are clearly known. For example, it has been recommended that conservation supply functions be developed and incorporated within Ontario Hydro's planning process. Monitoring and post-audit systems to determine the amount of savings actually achieved under specific DSM programs are also suggested as a means of better quantifying DSM potential. Many analysts believe that these initiatives would greatly reduce the current uncertainty surrounding the impacts and relative costs of DSM.

To be effective, all types of DSM programs require an in-depth understanding of customer attitudes and behaviour. Monitoring the effectiveness of programs and evaluating public acceptance and customer savings keep customers and utilities in closer contact. Many utilities view this to be a plus, even if the other DSM benefits are not significant. DSM programs can also help to reduce the uncertainties associated with load forecasting.

Demand-side management is not, however, without some costs. The control and metering equipment can be expensive. There are also practical limits to system load factor improvement, as utilities schedule much of the maintenance for their generating equipment for

low-load periods. Large increases in load factor could result in higher fuel costs, as higher cost generation might be needed for longer periods of time. In addition, a kilowatt of load reduction on specific electrical devices may result in substantially less than a kilowatt of demand reduction at time of utility system peak, due to load diversity.

Assessing the attractiveness of a DSM strategy is a complex task because of data limitations, particularly the lack of information about customer responsiveness to DSM initiatives. The choice of the appropriate strategies requires that a utility have sufficient understanding of a number of customer characteristics, including demographics, fuel use patterns, end-use load shapes and customer attitudes toward utility programs. Obtaining this information can be costly.

The growing willingness to consider supply alternatives such as demand-side management and non-utility generation suggests that the development of competitive bidding schemes on the demand and supply side, similar to those under development in the United States, will materialize in Canada. The success of efficiency programs in the United States has also sparked support in Canada for compulsory energy efficiency standards rather than voluntary or price-driven measures. Taken together, these initiatives suggest that comprehensive least-cost planning--the examination of all economic supply options at a specified level of reliability--will eventually materialize in many regions across Canada.

Least cost planning is endemic to the regulation and development of Canada's electric power system. What has changed is that the rising cost of electricity, together with new technological developments and environmental pressures, has broadened the number of options which need to be assessed in least-cost power planning. Unfamiliarity with some of these new tools and their relative costs and benefits has caused many utilities to be conservative in adding them to their roster of supply alternatives. However, Canadian utilities are increasingly coming to recognize that managing demand can play an important role in planning for supply.

While the future of DSM appears promising, its rate of development is uncertain due to its rudimentary growth to date. However, pressures are mounting for significant growth as utilities and their regulators seek greater efficiencies in the production and end-use of electricity. Strategies aimed at ameliorating concern with

the environmental impacts of fossil-fuel combustion will add immediacy to this pursuit of greater system efficiency.

Fundamental market research and development (R&D) is essential and is underway in many parts of Canada, though critics argue that more must be done. This R&D will provide Canadian utilities with a better understanding of the actual costs and value of specific DSM programs. Comprehensive least-cost planning and competitive bidding for new supply seem destined to become fundamental in Canadian electric power planning. These practices have been under development in the United States for some time and their results could provide important insights to program development in Canada.

Non-Utility Generation

Non-utility generation (NUG) is a relatively new aspect of electricity planning in Canada. For many decades, Canada's electric utilities have supplied electricity by capitalizing on economies of scale. Up until the 1980s, independent power producers were not competitive with utilities due to the low costs inherent in electricity production from large-scale generating stations. However, increasing construction costs, economic and regulatory uncertainties, and changes in technology have altered this situation. Factors such as higher inflation and interest rates, more stringent safety and environmental standards, volatile fuel prices, and unexpected changes in electrical demand growth have exerted upward pressure on production costs for the utilities, which in turn has reduced the attractiveness of adding large new blocks of conventional generating capacity. These factors have called increasing attention to the potential role of non-utility generation, particularly cogeneration.

Non-utility generation is not, however, a substitute to central utility generation. In most provinces, NUG could not alone match the generation supply required to meet forecast levels of electricity demand. Moreover, non-utility generators are not committed to serve in the same way as a central utility. Reliability of NUG electric power supply may also limit its economic attractiveness. Determining a price that reflects the "social" value of non-utility generated power is a further complicating issue. While experts generally agree that the buyback rates offered to non-utility generators should reflect "avoided cost" principles, it is not clear how these rates should be set, or by whom.

Four provinces currently support NUG: Ontario, British Columbia, Alberta and Quebec. Ontario Hydro, for example, is diversifying its generation mix and plans to acquire about 1000 MW from non-utility generators by the year 2000, although the Ontario Ministry of Energy cites 2000 MW as a more feasible target. In December 1988, B.C. Hydro requested proposals for NUG supply for its integrated system of up to 150 MW. It followed up later with a purchase policy indicating that requests for proposals totalling 25 MW (from projects less than 5 MW) will be issued annually. In Alberta, a 5-year program is underway to assess the advantages and disadvantages of greater reliability on non-utility generation.

While interest in NUG is emerging in some provinces, many utilities remain generally unsupportive of independently generated power, citing reliability as their primary concern. Further development seems likely, however, as the availability of inexpensive conventional sources of supply diminishes and utilities are forced to consider alternative supplies. Greater recognition of the potential of NUG, together with a growing number of independent power suppliers, could eventually lead to comprehensive power purchase policies and the abandonment of existing project-by-project negotiations. These developments go hand-in-hand with the evolution of supply- and demand-side competitive bidding programs.

The U.S. experience with NUG, fostered by supportive legislation, is an important point of departure for Canadian utilities and policymakers. For more than a decade, U.S. non-utility generation has been actively supported. While the U.S. experience has not been entirely positive, Canadians could benefit from modifying some U.S. programs to Canadian conditions.

Competitive bidding programs are a case in point. An appraisal of the Federal Energy Regulatory Commission's (FERC) competitive bidding proposals and those addressing the calculation of avoided costs is relevant to Canada. Recently completed studies by the FERC on transmission pricing and access also provide valuable insights on ways of addressing Canadian market impediments to non-utility generation and interprovincial electricity trade.

Despite the insights gained in looking to experiments south of the border, *Canadian* research is needed to pinpoint the role for non-utility generators in electricity supply for the 1990s. There is a clear need to quantify the amount of electricity that can be provided by independent power producers, and to evaluate the number of

megawatts that could be supplied at different price levels. Issues such as the reliability and availability of NUG power supply, the provision of market access and appropriate purchase rates, as well as the appropriate role of regulatory agencies, are fundamental to greater efficiency and require analysis and demonstration.

Electricity Trade

The economic benefits of electricity trade and greater coordination in electric power planning lie largely in the economies of scale and the advantages of diversity in load, risks and operating costs. Capital costs are reduced through the use of larger generating units which cost less to build per unit of output, and through the lower reserve margins which result from reducing the ratio of generating unit size to combined system peak load. Operating economies are gained through the load diversity of the combined systems, reduced operating costs per unit of output, and more complete use of the lowest cost generation available to the systems. Additional savings are possible through coordination of construction programs which minimize the costs of temporary excess capacity resulting from the addition of generation in stepwise blocks. Reliability benefits stem from a reduction in reserves required to achieve a given level of reliability, or as an increase in the level of reliability of the coordinated systems.

The benefits of electricity trade are substantial. A recent U.S. evaluation showed total national savings of \$15 billion per year in the bills electricity consumers paid in the last few years, resulting from inter-utility coordination and power pooling. If not for the inter-company coordination presently practised in the United States, about 14 percent more generating capacity would have been required to maintain adequate reliability.

The prospects for firm power exchanges between Canadian utilities are intertwined with the development of trade opportunities in the United States. This results from the fact that the cost of U.S. generated power is higher than that in Canada, making U.S. destinations the principal focus for Canadian utilities interested in the economic spin-offs that would accrue from greater trade.

To account for this interdependency and to evaluate the potential benefits of greater coordination in Canadian electric power planning, the Canadian Energy Research Institute and the Alberta Research Council (ARC) developed a model (ELGEM) of optimal electricity trade flows within Canada and between Canada and the United

States. Detailed model assumptions and data, together with the results of various simulations are provided in Volume II of this study.

ELGEM provides a comprehensive analytical framework for regional electric power planning over the 1988 to 2009 period. Canada is divided into eight regions, with the Maritime provinces considered as one region and all other provinces treated individually. The United States is treated as four potential market regions.

In the ELGEM model, only transmission links from Canadian regions to other Canadian regions and to contiguous American regions are considered. The model schedules capacity and transmission additions to minimize the cost of meeting forecast demand for electricity in the United States and Canada, subject to non-economic or political constraints imposed on the modelling system.

The reference, or "business as usual" case, is represented by Case 1 in Table 1. No additional trade transactions are assumed to occur other than the long-standing Hydro-Quebec and Newfoundland sale, together with those contracts which have already been signed between utilities in Canada and the United States. As no incremental trade is assumed either domestically or for the export market, the Net Present Value (NPV) of trade savings is zero. As shown in Table 1, the total capital and operating cost of meeting forecast peak and energy demand in Canada and the United States is represented by the objective function value of \$1619 billion (\$1988 Cdn.).

Case 2 assumes full interregional integration in electric power planning. No non-economic constraints are imposed and generation and transmission capacity are added when and where economically desirable. This scenario results in an objective function of \$1593 billion (\$1988 Cdn.) for a savings in the total cost of generation and transmission required in Canada and the United States relative to the base case of \$26 billion (\$1988 Cdn.). Therefore, full integration results in a significant reduction in the total cost of new generating capacity and significant revenues for Canadian electric utilities. As most of the displaced generation would be fossil-fuelled, unrestricted trade would also result in a significant reduction in environmental emissions, much of which would fall on eastern Canada owing to prevailing wind patterns.

Relative to the "No New Trade" scenario, the Net Present Value (NPV) of trade savings totals \$3.5 billion (\$1988 discounted Cdn.); inter-utility trade within Canada accounts for \$130 million or

TABLE 1
ELGEM TRADE SCENARIOS

Case	1				2				3				4			
Scenario	No New Trade				Full Trade				No New Exports ^a				Full Trade			
Discount Rate (%)																
Generation Transmission	5				5				5				5			
	5				5				5				5			
Ontario Nuclear/Coal Ratio Objective Function ^b	0.5				0.5				0.5				1.0			
	1619				1593				1616				1593			
NPV Trade Savings ^c Canada Export	0.0				0.13				0.29				0.08			
	0.0				3.4				0.0				3.4			

SOURCES: The Alberta Research Council and the Canadian Energy Research Institute.

^aInterregional trade within Canada is maximized; exports to the U.S. are restricted.

^bBillions of undiscounted \$1988 Cdn.

^cBillions \$1988 Cdn. discounted at 5 percent.

only 4 percent of these savings. Electricity trade between Quebec and Ontario accounts for the lion's share of the Canadian trade component (82 percent); trade between Manitoba and Ontario accounts for the residual.

Case 3 examines a situation in which interregional trade within Canada is maximized but electricity exports to the United States are restricted. As shown in Table 1, the objective function falls to \$1616 billion, indicating a total savings of some \$3 billion (\$1988 Cdn.) accruing from greater Canadian interprovincial electricity trade relative to the "No New Trade" case. The NPV of Canadian trade savings increases from \$130 to \$290 million (\$1988 discounted Cdn.) with Quebec - Ontario trade accounting for 89 percent of this total. Total discounted revenues from exports, however, fall significantly relative to the unrestricted trade scenario.

The potential savings in capital and operating costs resulting from greater electricity trade are sizeable. Moreover, as the majority of the electrical generating capacity that would be displaced would be fossil-fuel fired, significant environmental benefits could also accrue from greater trade.

Increasing recognition of the benefits to be derived from greater trade is required so that consumers have a more balanced understanding of the benefits and costs of this supply option. The planning environment of electric utilities and their regulators must also be broadened to encompass electricity trade as an important component of least-cost planning. Electricity trade and coordinated electric power planning should be considered on an equal footing with options such as conservation, demand-side management, non-utility generation and conventional generating capacity.

While past studies have pointed to the benefits of integrated power planning, serious effort in support of greater interprovincial trade is only now starting to emerge. To augment Canadian energy efficiency and reduce environmental impacts, a comprehensive examination of the costs and benefits of greater inter-utility trade and coordination should be undertaken. Owing to the cost and complexity of the issue, this study could only go part way to addressing "net" trade benefits. In fact, this broader focus appears imminent as the National Energy Board gears up to review and report on ways to:

- enhance interprovincial trade in electricity;

- encourage greater cooperation between utilities in systems planning and development; and
- enable buyers and sellers of electricity to obtain commercial access to available transmission capacity through intervening provinces for wheeling purposes.

Environment

All of the above are important to the most pressing issue facing Canada's energy industry--the environment. The environment will become increasingly important in utility planning, rivalling electricity demand and fuel costs as the single most important source of uncertainty facing Canadian utilities over the coming decade. In fact, environmental protection is the cornerstone of increasing interest in DSM, NUG and electricity trade as means of improving efficiency in production and end-use of Canadian electric power.

Environmental concerns and their impact on Canadian electric utilities pertain to the following areas:

- lack of information regarding the benefits and costs of remedying environmental externalities;
- the future course of public policy; and
- public attitudes towards environmental issues in Canada.

Environmental policies will be affected as well by the need to achieve wide-scale international coordination on many environmental issues.

Environmental concerns in the form of public and political pressure, combined with regulations established over the past 15 years, will continue to influence the development of new hydro and nuclear power facilities. However, new environmental concerns in the 1990s will focus on controlling atmospheric emissions such as sulphur dioxide (SO₂), nitrogen oxide (NO_x) and carbon dioxide (CO₂). These comprise major components of the acid rain, elevated ozone and global warming problems. As electric utilities are important sources of these emissions, pressures to control these emissions will affect the operation of existing fossil-fuelled generating stations and will contribute to uncertainty in planning Canada's future generation and technology mix.

Regulation of atmospheric emissions will likely emerge in the 1990s as the environmental issue facing Canada's electric power sector. Utilities, public utility boards and governments will be forced to give greater recognition to the effects of regulation and to factors which promote greater efficiency, both of electricity supply and electricity end-use.

Pressures to reduce atmospheric emissions will be exerted by local, provincial and federal ambient air quality standards, public opinion, and most importantly, specific emission reduction targets established in response to international protocols and agreements.

For example, under the NO_x Protocol of 1988, Canada has agreed to reduce its NO_x emissions to 1987 levels by 1996. While specific federal/provincial agreements to implement this policy have yet to be determined, it is likely that Canadian utilities will be asked to bear a significant share of the targeted reductions.

The Canadian government is evaluating the CO₂ problem and is examining CO₂ emission reduction targets and abatement strategies. While an international agreement on CO₂ emission reduction is not expected in the near term, utility planning decisions in the 1990s may be influenced by such a possibility. **Suggested targets for reducing CO₂ emissions would have far-reaching implications on Canadian electric power and on the Canadian economy as a whole.**

The extent and nature of the response to existing and anticipated emission reduction targets have varied widely across Canada. Ontario Hydro has introduced an acid gas program which involves the following measures:

- reduce sulphur content of coal;
- introduce conventional control technologies such as scrubbers and low NO_x burners in existing facilities;
- examine the potential for the use of advanced clean coal technologies; and
- displace coal with demand-side management, nuclear power, hydro generation, increased trade and non-utility generation.

The costs of reducing acid gas emissions in Ontario may increase the cost of coal-fired generation by as much as 20 percent, and

thus accelerate the Province's move away from coal generation. The declining share of coal may mean that Ontario can meet its acid gas emission commitments with only modest increases in electricity rates. In other parts of Canada, notably those coal-committed provinces which do not have ready access to low sulphur coal and where significant new capacity may be required over the near term, acid gas emission controls will result in the cost of coal-fired generation increasing substantially.

The incremental costs of acid rain abatement may not be large enough to offset the perceived benefits of coal-fired generation in provinces like Nova Scotia, New Brunswick, Saskatchewan and Alberta. Here the development of indigenous coal resources is a fundamental component of energy and economic development strategies. Apart from the economic spin-offs associated with continued use of coal in some of these provinces, coal is also the most economic generation alternative. These provinces can be expected to accelerate the move towards advanced clean coal technologies which, according to many industry specialists, offer a solution to the environmental problems associated with coal combustion.

One of the *principal* sources of uncertainty facing the electrical sector today stems from escalating concern over increasing CO₂ concentrations on global warming. While Canadian utilities have generally adopted a "wait and see" approach to the CO₂ problem, any demonstrable increase in public concern over global warming would undoubtedly force Canadian utilities to consider the implications of CO₂ controls for future planning decisions. **Unlike acid gas, no feasible technology currently exists for controlling CO₂ emissions in the combustion or flue gas stages.**

While the dimensions of the CO₂ problem are massive and considerable scientific uncertainty clouds the extent and timing of "global warming," the Canadian federal government is, nevertheless, marching ahead very quickly. Environment Canada Minister, Lucien Bouchard, has stated that a policy for reducing greenhouse gases will be ready in the spring of 1990 and that it could radically change Canadians' way of life.

What is confusing about the *March to Contain CO₂* is that politically-inspired policy is seriously out of step with the scientific and technical understanding of cause and effect. This confusion is resulting in a considerable muddle in policy planning directed to analysis of the most cost-effective ways of reducing CO₂ emissions. While

transportation and industrial processes account for the lion's share (60 percent) of Canada's CO₂ emissions, the electric power industry has seemingly been slated as the "target of choice." Other "targets" may yield more significant and less costly means of reducing CO₂ emissions.

The key point is that there are many natural and man-made sources of CO₂ (see Figure 1). All sources should be examined to determine the best means of implementing a significant reduction in Canada's CO₂ emission levels. Targeting Canada's electric power sector may not be the most cost-effective means of expeditiously reducing Canada's CO₂ emissions, particularly when all the uncertainties and complexities associated with "global warming" are accounted for. Quick-fix, politically-inspired policies may prove wasteful and counterproductive in effectively dealing with the challenge of environmentally sustainable development.

For the foreseeable future, it seems that the best options available for reducing CO₂ emissions in the electrical sector are limited to fuel switching and improved efficiency, both in fossil-fuelled combustion and electricity end-use.

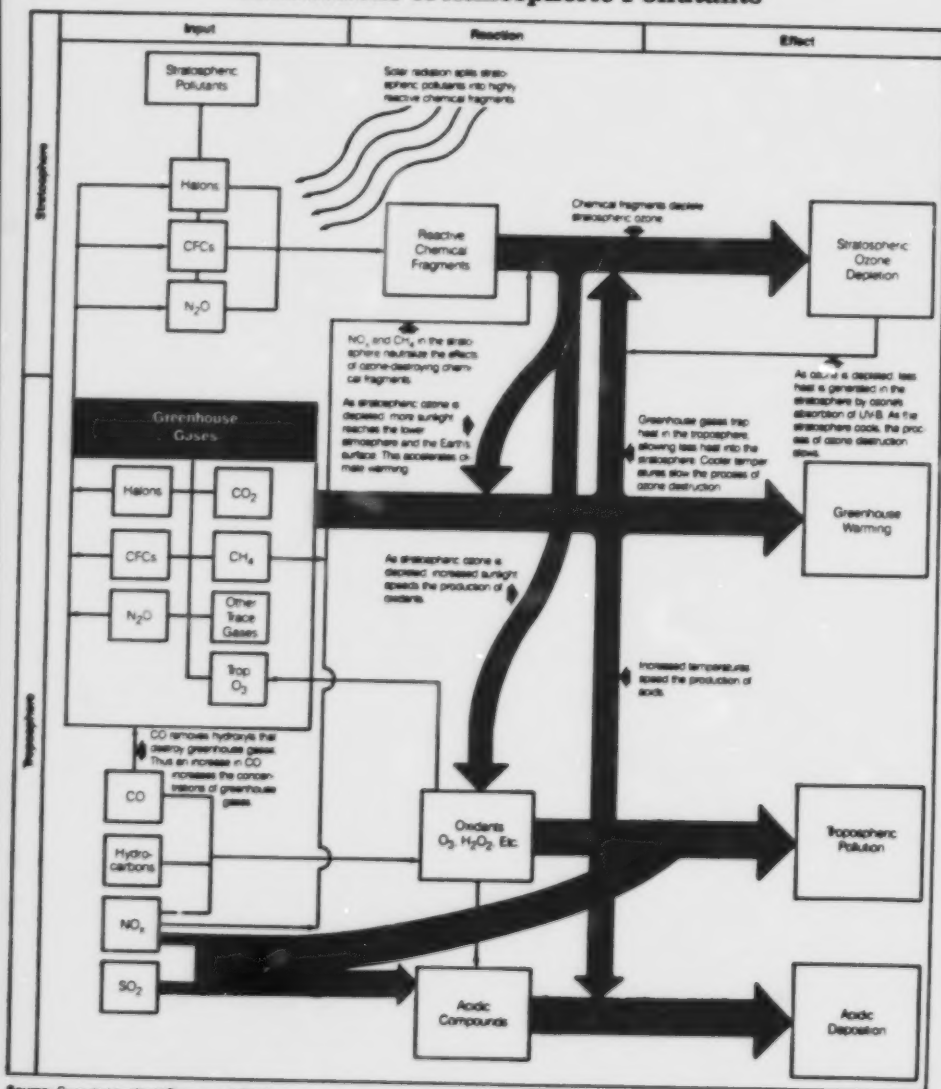
Advanced clean coal technologies are currently in the demonstration stage and while they appear capable of offering sizeable improvements in generating efficiency, it is uncertain whether efficiency improvements of this nature alone would be capable of achieving (as yet unspecified) reduction targets.¹ More likely, a combination of fuel switching and improved efficiency at both the production and end-use stages will be required to achieve a meaningful reduction in CO₂ emissions.

It seems very likely that increased uncertainty with respect to the future costs of alternative forms of electricity generation will cause utilities to postpone decisions regarding new capacity additions. In common with developments in the United States, it is also likely that Canadian utilities will place greater emphasis on power pooling, demand-side management, non-utility generation (particularly cogeneration) and energy efficiency programs in various end-use sectors.

Conclusions

The objective of this research project was to assess some of the more important issues bearing on the future development of

Figure 1
Interactions of Atmospheric Pollutants



Source: Compiled by World Resources 1988-89

Canadian electric power. The underlying emphasis has been one of greater rationalization or efficiency in the provision and end-use of Canadian electric power. The cornerstone of this interest in greater efficiency stems from a wide-ranging concern with the environmental impacts of energy production and use.

Canada's electric utility industry has been buffeted by numerous changes in economic climate and regulatory and political attitudes over the past two decades. Still, the industry remains a vibrant and fundamental component of our economic growth and high standard of living. Canada's electric utilities have attempted to minimize power costs and provide high levels of reliability to their customers. This least-cost operating strategy, reinforced by government regulation, has in many cases caused utilities to respond conservatively to new pressures and changing trends. Some suggest far too conservatively.

While least-cost planning remains the hallmark of utility planning, greater economic uncertainty has complicated the assessment of the least-cost generation mix required to meet the forecast, but uncertain, levels of electrical demand.

There are many more factors to consider in minimizing costs and providing economic and reliable electric power to end-use customers than was the case in the past. Demands on the industry to take greater responsibility for the environment, non-utility generation, trade opportunities and management of demand are but a few factors that have added to the complexity of electric utility planning. The task seems destined to become no easier in the 1990s.

In some cases, as many of these demands have gone beyond the expertise housed within the utilities, the response has been conservative so as not to compromise existing customer service levels. However, Canada's electric utilities are marshalling their resources to examine the potential and appropriate role of demand-side management, non-utility generation, and public concern with the environment. Research and demonstration programs are underway in some regions and more will be undertaken to ensure that incorporation of these new factors is complimentary to the utilities' least-cost planning practices.

In some areas, the ability of the utility to act has also been hampered by outdated regulation. Clear policy statements from provincial and federal authorities are required to ensure that Canada's electric utilities are working in concert with clearly enunciated policy

directives. In many cases, formalizing these policy statements will require considerable time and cost.

In many regions, the dictates of ensuring reliable and inexpensive electricity have forced crown-owned utilities to build new, larger generating units without a clear regard for other options which could permit greater flexibility and lower long-term costs. Moreover, the directive of producing only one product--electricity--has often led utilities to dismiss the importance of competitive products such as natural gas and end-use efficiency. This one-product mandate has sheltered the producer from an understanding of how their customers use electricity. Many things have changed and it is imperative that regulations governing the utilities keep in step with changing times.

For example, electricity trade is an area where utilities and their regulators should undertake a fundamental review. Regulatory changes at both the provincial and federal level will be required if utilities are to fully take advantage of the benefits of greater trade. Reduced emission levels and somewhat lower electric power rates would result from more coordinated electric power planning in Canada.

Immediate R&D on the environment and the appropriate utility response is also called for. However, the right context must be set by federal and provincial policy guidelines which account for the implications of changes in emission levels on the industry and its customers. Equally important are equity considerations--controlling electric utility emissions must be assessed in a broad context where consideration is given to the most cost-effective means of reducing emissions from all sources--both energy and non-energy sectors of the economy (e.g., agriculture and forestry).

Government and utility R&D must also be realigned as global environmental problems dictate consideration of cost-effective solutions that go beyond what Canada alone can do to limit emissions. Global problems sponsor complex questions and tradeoffs--what allocation of funds should go to (i) energy efficiency programs; (ii) clean coal technologies; (iii) demand-side management; (iv) non-utility generation; (v) forest fire prevention; or (vi) aid for energy efficiency and reforestation in developing countries? The uncertainties regarding costs, implementation, customer acceptance, and context (regional, national and international) add layers of complexity to an important and already complicated problem. These factors also underscore the

fact that the analysis of the best means of reducing greenhouse gases will require considerable time if it is to be done right.

Recommendations

Many of the issues discussed in this study will be important points of departure for research, development and demonstration (R, D&D) by Canadian utilities in the forthcoming decades. However, some of these issues are of immediate importance, particularly to utilities under pressure to bring on new generating capacity. Consequently, the priority of research initiatives will differ on a region-specific basis.

- **General policy: encourage energy efficiency in the production and use of electricity in all sectors of the economy to encourage overall productivity performance and reduce environmental impacts.**

Electricity Trade

A thorough assessment should be undertaken immediately of ways to enhance interprovincial electricity trade and greater cooperation between utilities in systems planning and development. This assessment should recognize greater electricity trade as a least-cost energy strategy. The National Energy Board and Environment Canada, in consultation with the electric utilities, should jointly assess greater interprovincial power planning so as to minimize environmental impacts. Greater public understanding of the **benefits and costs** of both interprovincial and international electricity trade is fundamental.

Non-Utility Generation

Non-utility generation should, *where practical*, be actively supported. The potential of this supply alternative should be evaluated in the context of a comprehensive review of U.S. state practices and FERC initiatives on avoided cost and competitive bidding program structures. Cogeneration and utility/industry partnerships should be encouraged by regulators. The Canadian Electrical Association is an appropriate body to direct this research.

Demand-Side Management

To reduce uncertainty about the cost and effectiveness of demand-side strategies, an assessment should be undertaken of the different programs available and under use by various electric utilities

in the United States and abroad. This assessment should also consider the availability and usefulness of least-cost planning models to utilities in Canada. Work done by the Electric Power Research Institute, the Edison Electric Research Institute, the Northwest Power Planning Council, the National Regulatory Research Institute, Central Maine Power and the Bonneville Power Administration would be good starting points for this endeavour.

Competitive bidding programs under development in the United States should also be examined for their applicability to Canada. The Canadian Electrical Association seems an appropriate entity to undertake a survey of competitive bidding practices (demand- and supply-side) in the United States and evaluate the practicality of the various programs to Canadian electric utilities.

Environment

Environmental concerns are at the forefront of issues facing Canada's electric utilities and the drive to increase efficiency in production and electricity end-use. Significant R&D is required to evaluate flue gas desulphurization, fluidized bed combustion, integrated coal gasification combined cycle, advanced combustion technologies, coal beneficiation, sorbent injection and increased efficiency of existing generating units.

Environmental concerns point to an evaluation of alternative "environmentally friendly" sources of supply such as non-utility generation, greater electricity trade, demand-side management, and a shift to lower carbon fuels such as natural gas and small hydro. Government should do more, not less, to accelerate these trends--R, D&D budgets should be *increased*, not reduced, particularly now when energy prices are low. **When energy prices are high, it is already too late to undertake fundamental, proactive R&D.**

Specifically:

- Establish objective criteria to determine the full environmental cost of all existing fuel sources, alternative fuels and technologies.
- Investigate the least-cost options for meeting national and international protocols in energy and non-energy sectors of the economy.
- Review national energy policy in light of changing energy-economy-environment conditions, the growing

role of electricity, and long-term national and regional objectives.

- Advance the development and commercialization of clean coal technologies.
- Evaluate federally-directed research and development and foreign aid in a context which examines all of Canada's least-cost options for meeting international environmental protocols.
- Examine and evaluate policy options for implementation of environmental goals. The distortive effects of such policy tools on energy markets and the distribution of associated costs across all the players involved must be assessed and clearly understood prior to selection of an optimal policy instrument.
- Examine CO₂ sinks, such as reforestation.
- Investigate the costs and regional and national economic impacts of changes in environmental regulations.
- Examine means of increasing the average fuel efficiency of Canada's transportation network, as this sector is largely responsible for NO_x and CO₂ emissions.

In order to minimize the impact on utility planning of uncertainty over the volume, distribution and control requirements of environmental emissions, governments should:

- Support research directed to evaluation of the environmental implications of human activities, especially in the energy sector;
- Collect information on the course of government and industry response in other countries and make the Canadian position known through participation in international forums on the environment;
- Provide complete information to the Canadian public so that attitudes and decisions can be formed on the basis of the best information available;
- Continue to work on all facets of the environmental problem with all the major stakeholders; and
- Establish objective criteria to judge the full environmental cost of each fuel source and assess alternative fuels and technologies.

As SO₂, NO_x, VOCs, and CO₂ emissions all result from the combustion of fossil fuels, it is imperative that an examination be made of all sources of emissions at the same time, so that time and money are not needlessly spent discussing controls for one which are later made redundant by controls for another. A comprehensive approach, not a band-aid approach, is required if public funds are to be spent wisely in managing Canada's economy-environment interactions. More research and consultation must attend future government initiatives. Canadians need balanced and intelligently planned environmental initiatives which do not cause unnecessary harm to our economic and employment base.²

Footnotes

¹The Coal and Electricity Division of the Canadian Energy Research Institute is undertaking an assessment of the potential for new power technologies to reduce CO₂, NO_x and SO₂.

²Calgary Chamber of Commerce, "Environment and the Emerging Political Agenda," revised September 1989 submission to the Canadian Chamber of Commerce (Calgary, Alberta: Calgary Chamber of Commerce, September 1989), p. 4.



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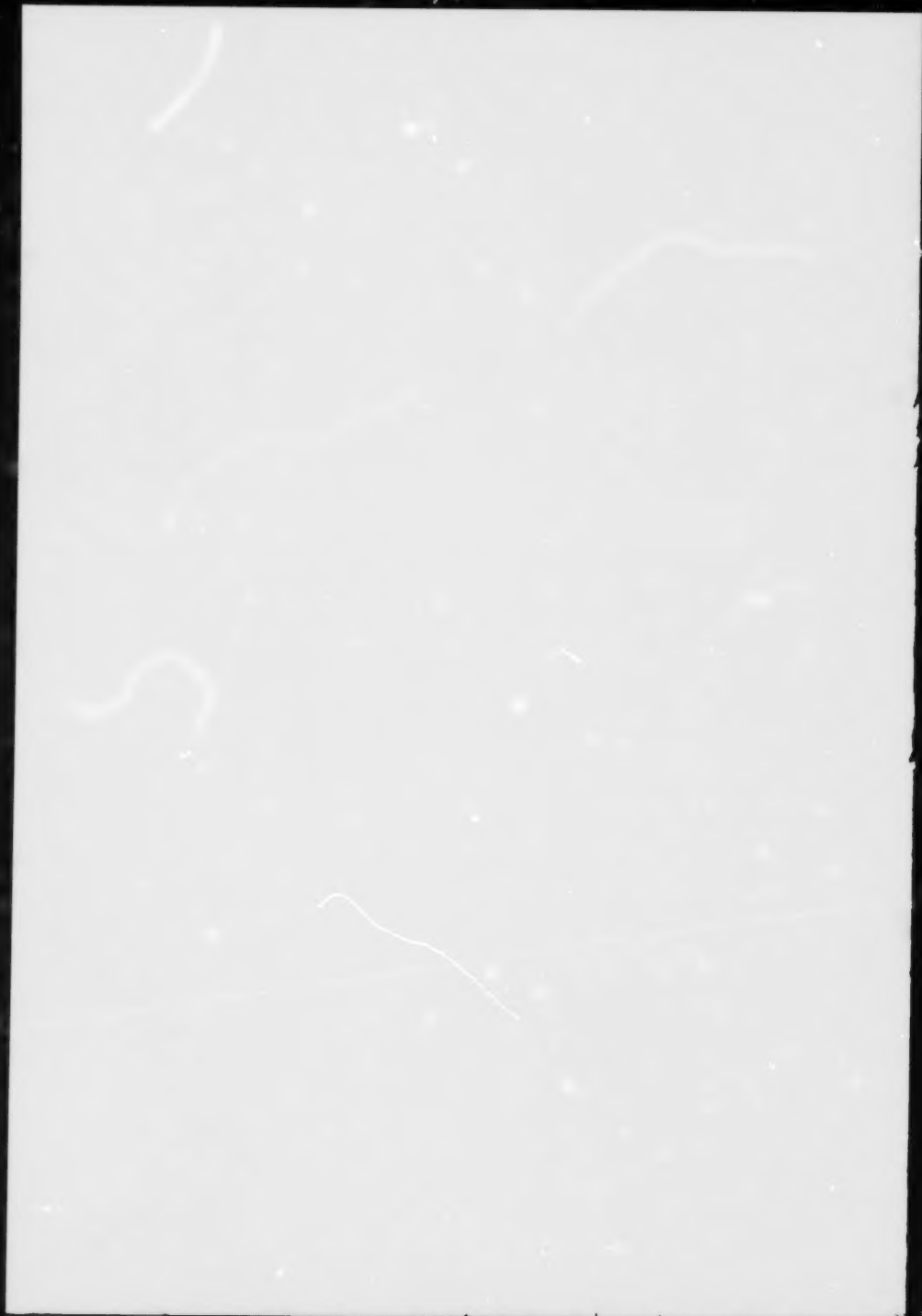
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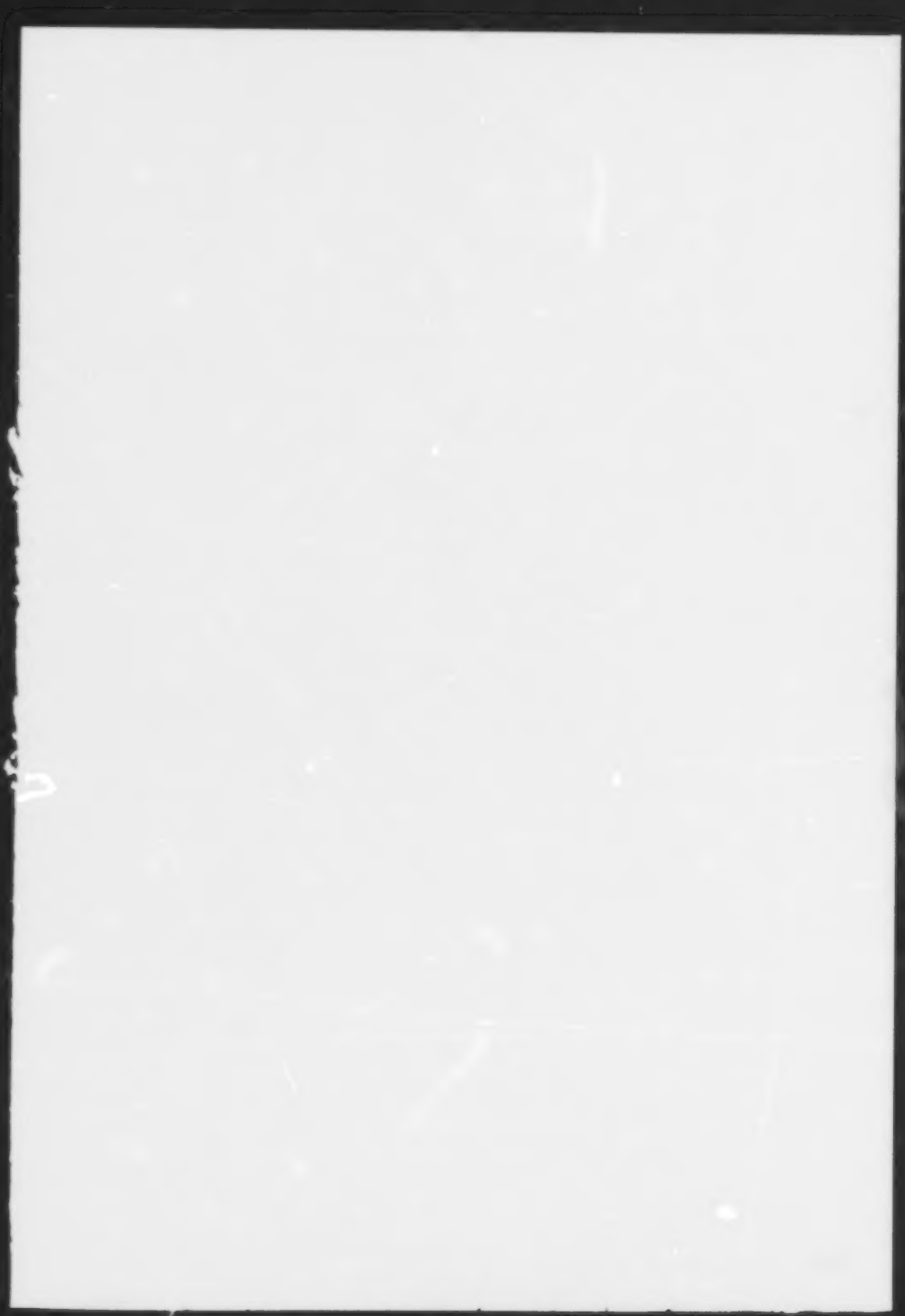
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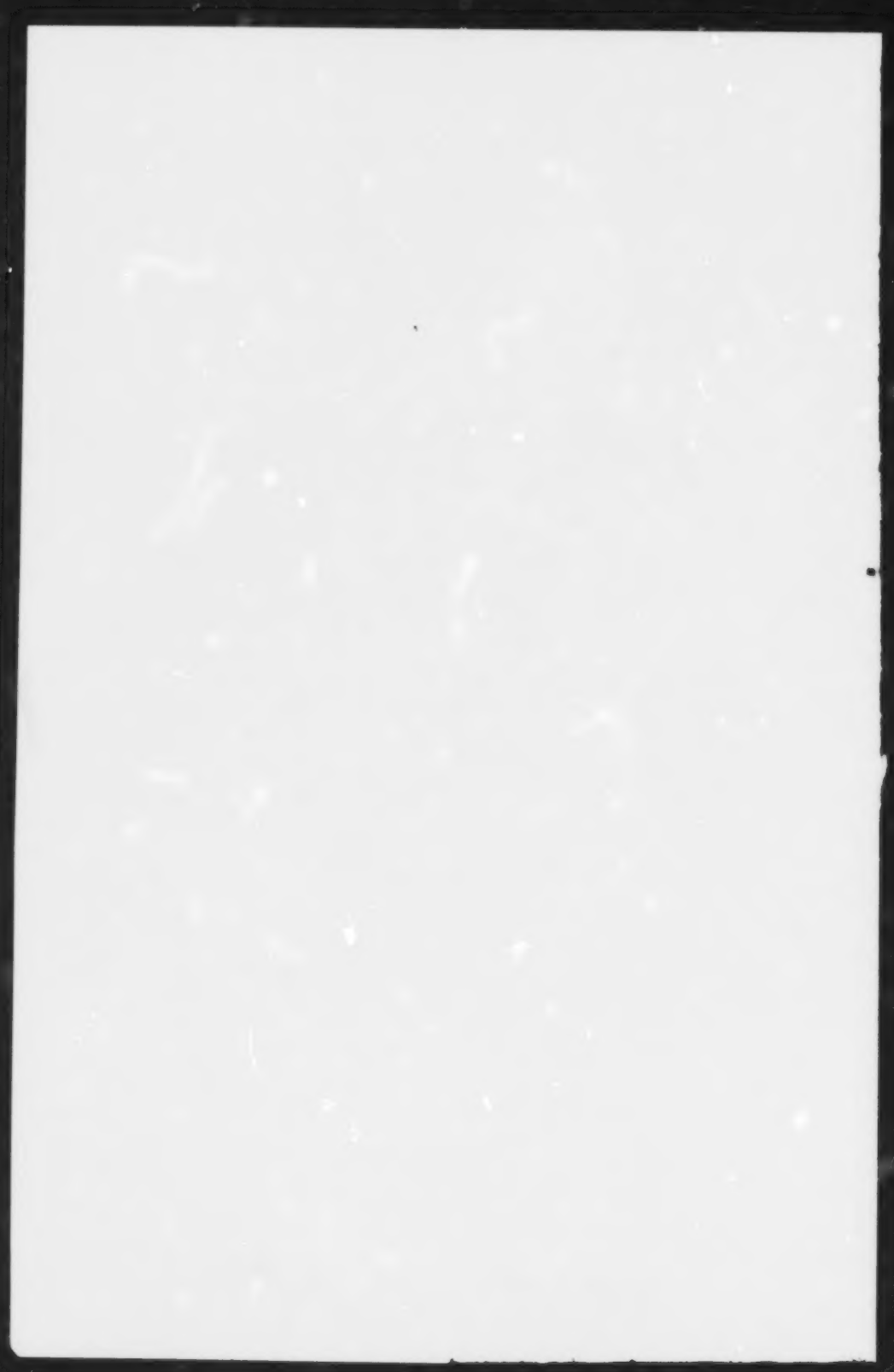
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**CRITICAL ISSUES IN ELECTRIC POWER
PLANNING IN THE 1990s**

VOLUME I

K. MORGAN MACRAE

**Critical Issues in Electric Power Planning
in the 1990s Volume I**

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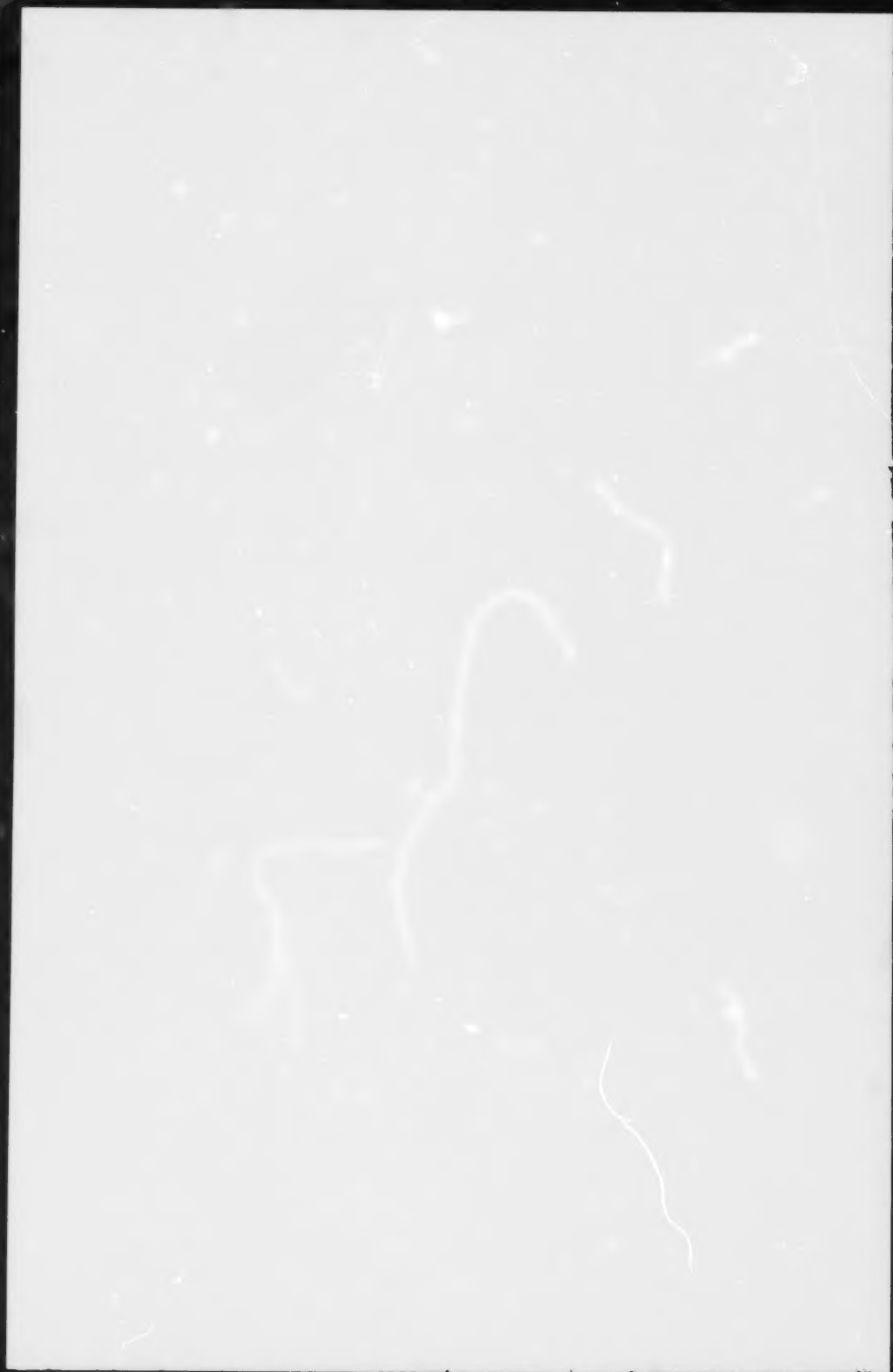
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The Canadian Energy Research Institute (CERI) is a cooperative research organization established by government and industry parties in 1975. The Institute's principal role is to undertake objective, independent studies and thereby assist business and government in making energy and energy-related decisions and policy choices. Related important objectives are the ongoing government/industry review of energy issues and policies, the development of expertise in the analysis of energy matters and the general enhancement of public understanding of Canadian energy affairs.

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Preface

This project was a joint undertaking of the Canadian Energy Research Institute (CERI) and the Policy Studies Group of the Energy Policy Sector of Energy, Mines and Resources Canada. The project was conceived to address the myriad of important and, at times, controversial issues contributing to a period of significant change and uncertainty in the Canadian electricity industry.

CERI would like to thank the Policy Studies Group for their participation and acknowledge the following contributions. Sonia L'Heureux, Baxter MacDonald and James Stanford researched and wrote the provincial electricity vignettes contained in Volume II of this report. James Stanford was responsible for Chapter 2 on future capacity additions in the Canadian electricity industry and authored the historical overview of the industry contained in Volume II. Sonia L'Heureux co-authored Chapter 4, dealing with non-utility generation; Baxter MacDonald co-authored Chapter 6, dealing with the environmental constraints that will strongly influence utility planning decisions in the 1990s. Paul-André Rochon and Nik Marty of the Policy Studies Group assisted CERI in the design and management of the study.

Two other organizations made significant contributions to CERI's research. I would like to acknowledge the valuable work undertaken by Dr. Adrienne Kwaczek, formerly of the Alberta Energy Resources Conservation Board (ERCB) on regulatory developments in the United States (Volume II). Thanks is also due to the Alberta Research Council and, in particular, the contributions of Drs. Don Quon and Sam Wong who developed a model for CERI to assess future electricity supply, demand and trade patterns. Also acknowledged is the assistance of Mr. B. Emmett, formerly with Energy, Mines and Resources Canada and Dr. P. Prince (ERCB) for their assistance in arranging staff support from these organizations for this project.

The many individuals who served on the Advisory Committee to this study also contributed in a major way and their support and advice is gratefully acknowledged. As with all CERI research projects, the Advisory Committee offered their insight and constructive criticism on the draft report. The Advisory Committee was composed of

experts from 15 organizations representing industry, government, and academia in Canada, the United States and abroad.

Special thanks are due to a number of the Institute's staff: Janice Morrison and Beverly Kovacs, who processed the interim drafts and final manuscript; Megan Murphy, who created the graphics; and Zaytoon Janjua and Wendy Faid of the I.N. McKinnon Memorial Library, who gathered source materials from across the continent. Finally, my thanks to my colleague, Tony Reinsch, for his careful review and insightful comments.

This study brings together historical and current information on Canada's electric power system. An historical overview of Canadian electric power and the provincial vignettes contained in Volume II provide the context for Volume I where we discuss important issues facing Canadian electric power planning. This report specifically analyzes the current and prospective importance of a number of key issues, any one of which would be worthy of a detailed, book-length inquiry. To discuss all of these topics together required that the analysis be succinct and, at times, somewhat abbreviated.

The Institute hopes that you find this research study of interest, and that it addresses issues of specific importance. CERl is undertaking further analyses on Canadian electric power and to ensure the most pertinent research, we encourage your continued support, views and commentary.

Chapter 1

INTRODUCTION

Canada's electric power industry is going through some important changes in its regulatory and business environment. The effects of many of these changes will fully appear in the 1990s, although their roots may be traced to the turbulent 1970s and 1980s. The intent of this study is to examine, in some detail, those general factors which will influence the development of Canada's electric power system. Our interest in the evolving business environment of Canadian electric power stems from a number of general observations.

First, current and forecast demand for incremental electricity sales to the U.S. have led to major initiatives by Hydro-Quebec and Manitoba Hydro to establish long-term sales contracts with U.S. utilities. This has heightened concerns about environmental impacts and has raised questions of ratepayer liability in the event of economic or market changes in the period between approval and completion of the generation projects.

Second, the location of perceived export demand has heightened discussions over the wheeling of electric power from Newfoundland through Quebec to the northeast U.S., from British Columbia through the northwest U.S. to California, and potentially from Quebec through Ontario to the northcentral U.S.

Third, the environmental implications of current and proposed coal-fired and nuclear generation capacity have raised the question of alternative sourcing of incremental generating capacity and related issues of costing and pricing of electricity in both the domestic and export markets.

In addition, various forums have highlighted concerns that interprovincial transmission interties are less developed than Canada-U.S. interties. This impacts directly on the issue of wheeling of power and invokes the question of overall rationalization of Canada's electricity industry.

For example, is it in the nation's interest to have incremental growth on the Ontario Hydro grid met by additional nuclear or

fossil-fired generating capacity, or would it be preferable to have this demand sourced through firm purchase contracts from the hydro-based systems of Manitoba, Quebec or Newfoundland? Similarly, would Alberta or British Columbia benefit from increased synergy between the two provinces rather than having each province construct its own generating facilities? These questions have become fundamental with the release of Canada's Federal/Provincial/Territorial Task Force report on Energy and the Environment.¹

The potential for greater non-utility generating (NUG) capacity in Canada has also initiated considerable debate on the development of third-party sources of incremental generating capacity. The appropriate role of demand-side management (DSM) programs in electric utility planning is, as well, receiving increased attention in Canadian electric power planning. The public's concern with the environment places increased emphasis on efficient production and end-use of electrical power and consequently greater interest in DSM, NUG and electricity trade.

1.1 Focus

Foremost in our evaluation of issues effecting the development of the Canadian electric power industry is a "futures" assessment of those factors of importance to the Canadian public and to utility planners. We set out to examine a long and interrelated set of issues. We believe, however, the interdependence of many of these issues emphasize the importance of examining them in a single report rather than in a disjointed fashion. The general focus of our assessment centred on:

What are the critical or fundamental electric power planning issues for the next decade?

When are the major decision points likely to occur?

How will, or should, the utility industry respond to these pressures in the future?

An important pressure point on the horizon is the need for major capacity additions in most Canadian provinces during the 1990s. It is creating a serious dilemma for planners, policy makers and consumers of electricity. This is due to the fact that economies of scale, which brought falling unit costs in earlier decades, are reaching a limit. The most economical hydroelectric sites have largely been developed forcing utilities to look to more remote, expensive sites or to

alternative and costlier fuel sources such as coal, oil, gas or nuclear power.

This problem of increasingly expensive, marginal generating sites is compounded by rising capital costs and environmental constraints. On the one hand, dramatic increases in interest rates during the last decade augment the cost to utilities of their large capital investments. This is leading some provincial governments to question their guarantees of public utility debts and to argue for greater reliance on non-utility generation and demand-side management. On the other hand, the environmental costs associated with all types of centralized generation are under the scrutiny of native groups, anti-nuclear activists and those concerned with atmospheric pollution. How environmental pressures will influence the existing generating fuel mix is of increasing concern, both to utilities and their customers.

In light of these pressures, utilities need to closely examine means of making the existing and planned electricity system operate more efficiently. Herein lies the motivation and major focus of this study: the critical issues facing the industry are in the areas of trade, non-utility generation and demand-side management, with the environment being the cornerstone of the drive to increase efficiency in the 1990s. The expected need for new capacity additions is the backdrop which will shape the way that utilities, regulators and electricity consumers deal with the challenges of the 1990s. On the one hand, environmental concerns will constrain the ability of utilities to meet future supply requirements without sizeable cost increases. On the other hand, trade, non-utility generation and demand-side management will provide utilities with opportunities to manage supply and demand with methods complimentary to the traditional approach of adding conventional electric generating capacity.

The options that are available to utility planners have been made feasible by changes in the economics of electricity generation, by changes in technology, and by changes in social attitudes towards the environment and other externalities associated with the electricity industry. It is expected that the attitudes and policies of the utilities and the structures of regulation which govern them will lag somewhat in adjusting to this new business environment. Nevertheless, it is the purpose of this study to identify and quantify, where possible, the potential benefits of these new electricity planning options, and to propose measures to help realize these benefits.

1.2 Modelling

In view of the complicated and interrelated aspects of many of the factors affecting future demand and supply of electric power, the Canadian Energy Research Institute (CERI) believed it was important to develop a comprehensive analytical framework which would allow a broad assessment of the future trends in Canadian electric power generation, transmission and trade.

To accomplish this, CERI and the Alberta Research Council (ARC) developed an Electricity Generation Planning Model (ELGEM) of the electricity sector in Canada and the northern United States, incorporating various generation technologies including hydro, nuclear, coal and gas. This model gives a good indication of the comparative costs and benefits of greater electricity trade, though it is not as sophisticated as the utilities' economic dispatch models.

The structure of the ELGEM model is based, in part, on decision rules and cost data obtained from the electricity subcomponent of Energy, Mines and Resources' Interfuel Substitution Demand model (IFSD). This was supplemented with information from Ontario Hydro, results of the Ontario Nuclear Cost Inquiry and various other sources. Numerous constraints were incorporated in the ELGEM model to permit an evaluation of optimal interregional power transfers, both within Canada and between Canada and the United States.²

1.3 Outline

The following chapter discusses capacity additions required in Canada and sets the stage for the discussion of issues addressed in later chapters. These chapters deal respectively with demand management, non-utility generation, electricity trade and the environment. Chapter 7 concludes with the study's key findings and recommendations.

To assist in a broad understanding of Canada's electric power industry and its regional dimensions, a detailed historical overview of Canada's electric power system is included in Volume II. This volume also includes a series of vignettes which discuss the provincial dimensions of electric power and emerging issues of specific regional importance. For comparative purposes and for an understanding of factors which may come into play in Canada, Volume II also includes a chapter on the United States. It deals in large part with initiatives aimed at rationalizing the U.S. electric power industry.

The detailed assumptions and constraints of ELGEM, used to assess future interprovincial and international trade, is also appended to Volume II of this study.

Footnotes

¹Federal/Provincial/Territorial Energy Ministers' Task Force on Energy and the Environment, Report on Reducing Greenhouse Gas Emissions (Ottawa, Ontario: Federal/Provincial/Territorial Energy Ministers' Task Force on Energy and the Environment, August 1989).

²Information on ELGEM and the ARC's suite of energy models and their potential application to particular technologies or sensitivity cases can be obtained by writing the Oil Sands Research Department, Alberta Research Council, 1021 Hayter Road, Edmonton, Alberta, Canada T6H 5X2.

Chapter 2

FUTURE CAPACITY ADDITIONS

2.1 Introduction

Electric utilities in several Canadian provinces are facing an increasingly tight supply/demand balance. The chronic excess capacity experienced in many provinces over the last decade has been gradually worked off, and a number of utilities are once again facing the need to make significant additions to their resource base.¹

This need for capacity additions over the coming years will have important implications for other issues facing Canada's electricity industry--issues such as environmental protection, electricity trade, demand-side management and non-utility generation. Each of these topics is discussed in a comprehensive fashion in the following chapters. Yet the manner in which Canadian utilities are able to address each of these questions will depend in large part on the rate at which they must add new capacity. Provinces which face less pressing requirements for new supply will enjoy both greater flexibility and more time to implement these policies--be they cleaner environmental practices or effective demand-side management programs. On the other hand, those utilities whose generating facilities are inadequate to meet expected future demand will have to address these structural and policy issues in a more hurried fashion.

So it is evident that the rate at which new generating capacity must be added in Canada in the 1990s will be a fundamental determinant of the solution to the varied and sometimes controversial topics facing the industry. It is the purpose of this chapter, therefore, to discuss--in a preliminary fashion--the likely new capacity requirements faced by each province in the coming decade. The tentative results reported in this chapter provide a backdrop to the issue-oriented discussions contained in the following chapters.

This chapter is structured as follows: Section 2.2 addresses some of the qualitative issues related to the forecasting of electricity demand. Section 2.3 looks at the capacity additions that can be reasonably expected in Canada in light of the demand forecasts prepared by provincial utilities. A second set of results is provided in Section 2.4

as a sensitivity case, based on the assumption that the utility demand growth forecasts are an average of one percentage point too low. Section 2.5 examines the implications for future capacity development programs of the various firm electricity export proposals currently being pursued by Canadian utilities. Section 2.6 aggregates the most important results of the analysis, and explores their significance for the Canadian industry, in terms of fuel mix, investment requirements and other questions. The conclusions to the chapter briefly recap the most important findings of our analysis.

2.1.1 Analytical Approach

In the past, the most effective and economic approach was for the utilities to adopt a self-reliant, demand-driven strategy in their efforts to manage electricity supply/demand balance in each province. In other words, a utility would forecast future demand in its jurisdiction, taking this forecast (and an associated range of uncertainty) as a given. It would then plan to construct enough capacity to meet that expected demand. The demand in the utility's load area would be met almost exclusively with the utility's own generating facilities. Because of low production costs, there was little incentive to supplement domestic generating capacity with firm imported power. Similarly, utilities did not take a proactive approach to managing electricity demand, but rather simply accepted their duty as one of supplying whatever demand existed within its service area, in light of the prevailing price structure and regulatory regime.

This traditional approach to planning is undergoing substantial change. Utilities are increasingly coming to rely on external resources (either imported power or non-utility generation) to help meet domestic demand. Likewise, interventionist demand management practices, designed to encourage more efficient load structures and consumption practices, are and will become more prevalent across Canada.

These programs are in their infancy, however, and the economic and regulatory constraints which will shape them have yet to be fully analyzed and understood. The analytical approach taken in this chapter, therefore, will be one of *ceteris paribus*, that is, "all other things being equal." We will examine expected future capacity requirements in the various provinces, *assuming that no major changes take place in the supply strategies of the utilities--i.e., that they continue to accept electricity demand as an exogenous variable, and*

continue to plan to meet that demand in a self-reliant fashion from their own generating resources.

Since this assumption will almost certainly turn out to be incorrect (due to expected and radical innovations in policy on the environment, trade, demand management and non-utility generation), the results presented in this chapter *cannot be interpreted as a forecast*. Rather, they are simply an *illustration* of the relative supply pressures faced in each province, within the context of *existing* utility policies and regulatory structures. The actual capacity additions undertaken in each province will depend on the degree to which the supply/demand strategies taken by Canadian utilities change in response to the growing interest in alternative approaches to the planning of future electricity supply and energy resources. Thus, the results presented here must ultimately be considered in light of the points made in subsequent chapters, where the potential and the limitations of the various alternatives to traditional supply/demand planning are considered in detail. These chapters examine the impact that changes in electricity policy and practice will have on the generation capacity additions that *would otherwise have been expected* in light of current demand expectations and supply management methods.

2.1.2 Limitations of Forecasts

First, a few words of caution regarding the accuracy and reliability of the analysis which follows. The electricity industry is a notoriously difficult area of economic activity to forecast and interpret. In Canada, electricity supply is dominated by a handful of large generally publicly-owned utilities. Individual and discrete decisions of these utilities, which are subject to a range of powerful but volatile economic and political influences, can have a fundamental impact on the direction of the industry as a whole. These decisions are impossible to predict. So, any given forecast of electricity demand or generating capacity can be rendered out-of-date by a single economic or political development: a decision to proceed with a northern megaproject, a decision *not* to proceed with a construction project previously announced with great fanfare, a change in approach by regulatory bodies, or an unexpected shift in electricity consumption.

It is inevitable, therefore, that some of the information that follows will be proven incorrect—due to the shifting priorities of utilities, governments, regulatory agencies and electricity consumers. This recognition provides further reinforcement to our warning that these results should not be viewed as a forecast or a prediction. Instead,

they should be interpreted as illustrative of the relative demand and supply conditions that can currently be expected to prevail in the various provinces.

Similarly, the data which was used to form the basis of the analysis also limits the accuracy and timeliness of the results. The demand forecasts of individual utilities, for example, comprise a crucial component of our estimates of future capacity additions. Yet these forecasts are modified constantly in response to changing economic conditions and demand behaviour. Other published data on provincial peak demand, firm capacity and generating reserve is equally variable, and is often inconsistent between different original sources. This inability to draw a timely and truly accurate picture of the existing electricity market makes it even more difficult to estimate future trends in the industry.

These limitations all suggest that the exercise of analyzing the future development programs of utilities must be carried out with great caution. But if the results that follow are viewed in their proper context--as illustrative calculations of future capacity requirements, reflecting current utility and regulatory policies, and current expectations of the trend of electricity demand--they can nevertheless provide some useful insight into the supply/demand constraints that will govern the coming structural changes in Canada's electric power industry.

2.2 An Overview of Electricity Demand

The size and timing of future increases in Canadian generating capacity will depend first and foremost on the future course of electricity demand in Canada. Demand forecasts are a crucial ingredient in the development plans of utilities, and it is the uncertainty regarding future trends in electricity consumption that considerably complicates the planning process faced by utilities today. Most utilities are especially cautious in their present demand forecasting efforts, in light of their bitter experience of the last decade, when overly-optimistic demand expectations motivated them to plan and complete new capacity at a record rate during the 1970s, only to be surprised by the slowdown in demand of the early 1980s. This slowdown left many utilities with significant amounts of excess capacity, which could often only be utilized for the production of surplus power--sold at relatively low prices either to interruptible export markets or to bulk industrial customers. Today's high interest rates only reinforce the determination of utilities to avoid the over-construction of new capacity that

occurred in the 1970s, since the financial burden of under-utilized capital investment would be all the more weighty.

Sections 2.3 and 2.4 of this chapter develop two distinct scenarios of future electricity demand in Canada, which will be used to calculate indicative estimates of future capacity additions. Before developing our scenarios, however, some general comments on the nature of electricity demand and the difficulties in attempting to predict it are required. The first part of Section 2.2, therefore, identifies the various components of electricity demand in Canada today. The second subsection evaluates the degree of uncertainty which characterizes each of these components.

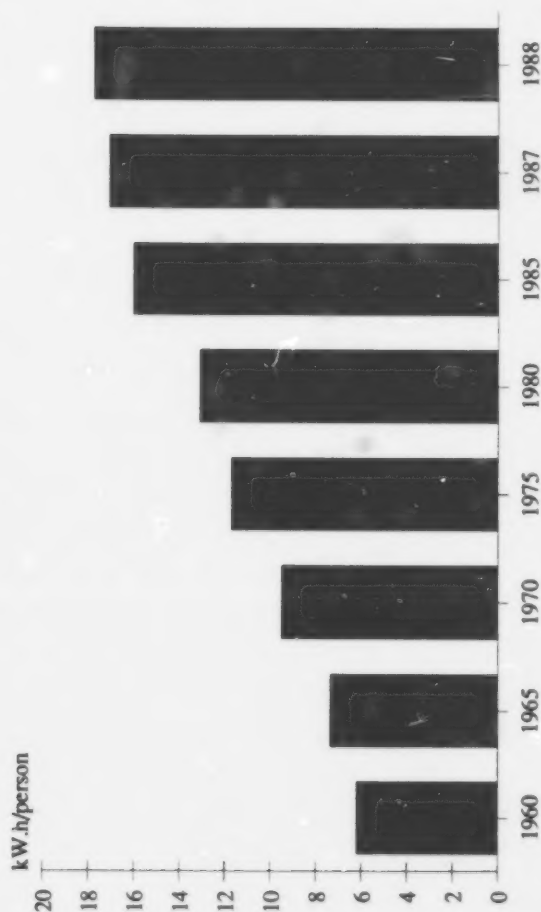
2.2.1 The Composition of Electricity Demand

Electricity is a convenient, flexible and relatively inexpensive form of energy that has become essential to a myriad of human activities. The use of electricity for so many different purposes in so many sectors of our society makes it especially difficult to evaluate the likely trend of electricity demand in the coming decades (see Figure 2.1 and 2.2). Moreover, the analysis is further complicated by the fact that the relationship between electricity supply and demand has been, and will continue to be, a complex, two-way interdependence. Early electricity supply developments were intended to meet a rather narrowly defined and specialized need: lighting, transportation (electric railways and streetcars) and certain power applications in the larger North American cities at the turn of the century. The emerging and increasingly efficient technology of electricity supply which developed in response to this demand, however, soon sparked whole new generations of electricity demand--such as electro-chemical smelting and refining processes, a variety of thermal industrial applications, and eventually home heating, electronics, and other uses for which electricity had never been initially intended.² Today this unpredictable and multi-faceted evolution of electricity demand continues to unfold, and its implications for the future supply planning of utilities are important. These factors are more fully described in the following sector-by-sector review of electricity demand.

2.2.1.1 Industry

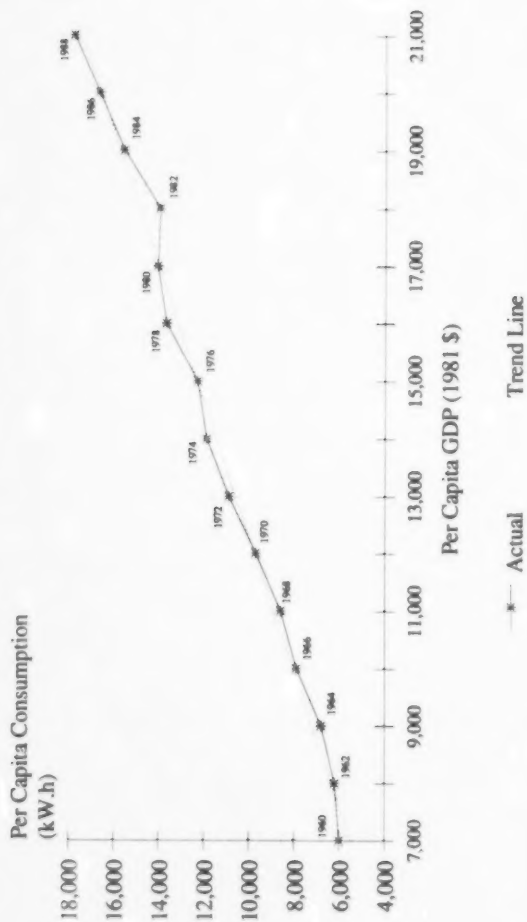
The industrial sector was the dominant power consumer throughout the early years of Canada's electricity industry, and remains the largest single source of electricity demand, responsible for one-half of total demand in Canada (see Table 2.1). Electricity's share

Figure 2.1
Per Capita Electricity Consumption
Canada, 1960-1988



SOURCE: Electric Power in Canada,
EMR Canada, 1989.

Figure 2.2
Historical Relationship Between
Electricity Demand and GDP, 1960-1988



SOURCE: Electric Power in Canada,
 EMR Canada, 1988.

TABLE 2.1
THE STRUCTURE OF CANADIAN ELECTRICITY DEMAND
1978 AND 1987

	1987			1978			Share of Electricity Demand Growth Attributable to	
	Electricity Demand (TJ)	Share of Total Electricity Demand (%)	Share of Total Energy Demand (%)	Electricity Demand (TJ)	Share of Total Electricity Demand (%)	Share of Total Energy Demand (%)	Increasing Energy Demand (%)	Market Share of Electricity (%)
Industry	797 278	50.4	28.2	577 145	50.6	24.4	50.9	49.1
Losses ^a	130 590	8.3	16.0	107 046	9.4	22.8	n.a.	n.a.
Mining	85 791	5.4	37.0	59 149	5.2	30.7	45.2	54.8
Pulp & Paper	191 529	12.1	52.7	123 511	10.8	35.3	7.0	93.0
Iron & Steel	35 887	2.3	12.8	28 046	2.5	9.1	-32.7	132.7
Smelt. & Refin.	130 208	8.2	72.4	102 457	9.0	62.1	33.7	66.3
Chemicals	64 318	4.1	25.9	44 351	3.9	24.1	77.3	22.7
Other	158 955	10.0	22.5	112 586	9.9	16.2	3.8	96.2
Transportation	10 682	0.7	0.6	6 930	0.6	0.4	2.8	97.2
Pipelines	7 842	0.5	7.7	5 133	0.5	49.7 ^b	n.a.	n.a.
Other	2 840	0.2	0.2	1 797	0.2	0.1	n.a.	n.a.
Residential ^c	429 527	27.1	34.6	310 303	27.2	23.3	-18.3	118.3
Commercial	345 318	21.8	36.1	245 360	21.5	28.4	26.5	73.5
Total	1 582 805	100.0	23.5	1 139 739	100.0	18.2	20.0	80.0

SOURCE: Statistics Canada, *Quarterly Report on Energy Supply/Demand*, No. 57-003 (Ottawa: Minister of Supply and Services Canada, various years).

^aIncludes producer consumption. "Share of Total Energy Demand" for this line refers to total producer consumption in the Canadian economy.

^bThe reduction in electricity's share of total pipeline energy demand between 1978 and 1987 reflects a change in reporting method, and does not reflect a relative decline in the use of electricity.

^cIncludes agricultural sector.

of total energy demand in the industrial sector was 28 percent in 1987, up by four percentage points from 10 years ago. Growth in industrial electricity demand during this 10-year period was due almost equally to this moderate increase in electricity's share of the industrial energy market, and to the overall increase in industrial energy consumption (see right-hand side of Table 2.1).

The pulp and paper and smelting and refining industries (the latter composed primarily of the aluminum industry) are responsible for more than one-fifth of all electricity demand in Canada. They are also the most electricity-intensive industries in Canada, with electric power constituting over 50 percent of all energy used in both industries. Note that because of the great contribution that both of these industries make to aggregate electricity demand, future investment patterns in these industries could have a dramatic impact on the electricity industry. Canada's pulp and paper industry, for example, is in the midst of a strong expansionary phase, and new investments in pulp and paper facilities today will have an important bearing on electricity demand in subsequent years. Other important consumers in the industrial sector include mining, chemicals, and the iron and steel industries, which together account for about 12 percent of all electricity consumption in Canada. Losses and producer consumption by the electricity industry itself constitute a further 8 percent of total domestic electricity use.

Technological change will exert a mixed and unpredictable effect upon industrial electricity demand in the coming years. On the one hand, improvements to both energy efficiency and to general manufacturing productivity can be expected to restrain some components of electricity demand. On the other hand, new production techniques may increase electricity consumption, even though they result in a net decrease in overall energy consumption. A good example of this is provided in the technology of thermo-mechanical pulping, which is being adopted by an increasing segment of Canada's pulp and paper industry. This technology uses less energy, but more electricity than other methods of production, and its adoption for energy efficiency reasons will increase electricity demand. It also produces a better quality product and results in less wood waste.

A similar pattern is experienced with the use of electric arc furnaces in Canada's steel industry. Electricity demand in this sector increased by close to 30 percent between 1978 and 1987, despite the fact that overall energy consumption in the steel industry dropped sharply due both to energy conservation and falling steel output. The

increase in electricity's share of the steel energy market, therefore, more than offset the decline in overall energy use, due primarily to the wider use of electric arc furnaces. These examples illustrate that the trend towards greater energy efficiency in Canadian industry can in many cases *augment* the demand for electricity, which is generally a more efficient and flexible form of energy for industrial purposes.³

2.2.1.2 Transportation

The transport sector was originally one of the more important sources of electricity demand; several of the first hydroelectric stations in Canada, for example, were built for the specific purpose of powering electric railways and urban transportation systems. Today, however, very little electricity is used for transportation--less than one percent of total electricity demand is consumed in the transportation sector, and electricity accounts for less than one percent of all energy used by this sector (with petroleum products, of course, being the dominant energy source). About 70 percent of electricity consumption in the transportation sector is used in pipeline compressor stations. It is possible that electricity may play a larger role in transportation in the future (primarily in cities for environmental reasons), but this potential is too removed to affect the current generation plans of Canadian utilities.

2.2.1.3 Residential

The residential sector is responsible for 27 percent of all electricity demand in Canada. Residential electricity consumption has increased by almost 40 percent over the past 10 years; this has been entirely due to increased market penetration by electricity, since total residential energy consumption has actually *fallen* by some 7 percent over the same period. As a result, electricity's share of total energy use in this sector has shot up, from 23 percent in 1978 to about 35 percent in 1987.

Off-oil conversion programs are primarily responsible for this dramatic increase. Particularly in the Maritimes and Quebec, and to a somewhat lesser extent in Ontario and British Columbia, electric space and water heaters have been widely installed in both old and new homes, sharply reducing the volume of home heating oils used by residences. It is primarily thanks to this process, for example, that New Brunswick and Quebec have experienced faster average annual increases in electricity demand than any other province over the past 5 years.

The rapid rate of recent demand growth in the residential sector is likely to slow down in future years for a variety of reasons. The number of oil-heated homes in Canada is dwindling, both in absolute terms and as a percentage of all homes, reducing the potential for further electricity demand growth resulting from off-oil conversion. General improvements to household energy efficiency--resulting from better insulation and more efficient refrigerators, water heaters and other major appliances--will restrain the increase in overall residential energy consumption. Finally, population growth is expected to slow in coming decades, reducing the rate of formation of new households. However, there are other forces at work, such as the increasing popularity of air conditioners and continuing growth in personal incomes, which could maintain demand growth rates in the residential sector at relatively high levels.

2.2.1.4 Commercial

This sector accounts for just over one-fifth of total electricity demand in Canada. Demand growth has been relatively rapid in recent years, aided by the same off-oil conversion trends experienced in the residential sector, and by the strong economic performance of Canada's service industries. Electricity's share of total energy consumption in the commercial sector increased by some eight percentage points between 1978 and 1987, to over 36 percent--making the commercial sector the most electricity intensive in Canada's economy.

Demand growth in future years in this sector is very unpredictable. On the one hand, it is expected that service industries will increasingly dominate Canada's economy; the electronics revolution could further boost this sector's electricity requirements. On the other hand, many untapped conservation opportunities exist such as the use of more energy-efficient lighting, which could restrain demand growth, especially if demand-side management programs are aggressively implemented.

2.2.2 The Uncertainty of Electricity Demand

Electricity demand in Canada is being pulled by two general but competing forces. In one direction, Canada's economy as a whole has become more *energy efficient* in recent years, relative to its size. This tends to reduce, on average, the amount of all energy required for human activity. This tendency will probably continue, motivated by economic, environmental and technological forces. Pulling in the

opposite direction, Canada's economy has become more *electricity intensive*. As Table 2.1 reveals, electricity now accounts for almost one-quarter of all energy use in Canada, compared to just 18 percent only 10 years ago. An estimated 80 percent of electricity demand growth over this period was the result of the substitution of electricity for other fuels; only 20 percent was the result of an expansion of Canadian demand for energy in general. New technology promotes energy efficiency in almost all cases, but in many circumstances it also contributes to this growth in electricity intensity at the same time. It is far from apparent which force will exert the more decisive impact on Canada's electricity industry in the coming decade.

The preceding discussion has shown that the aggregate electricity demand faced by utilities in Canada is ultimately composed of a vast array of individual final uses in different sectors of the economy. These uses, in turn, are subject to a great complex of factors--ranging from the growth and changing structure of Canada's economy, to future population growth, to the certain but unpredictable course of technological change--any one of which could render the most sophisticated demand forecasts of Canadian utilities meaningless. Part of the challenge facing utility planners is to try to reduce the uncertainty that derives from the complex nature of electricity demand, by gathering more accurate and timely information and by improving forecasting techniques. This is a significant undertaking as uncertainties in electricity market share and energy efficiency are compounded by uncertainties in economic growth. Part of the challenge will also be to more effectively understand the nature of uncertainty, and to *incorporate* this uncertainty directly into the planning process, rather than simply treating uncertainty as an "inconvenience."

For example, the future planning strategies of utilities will certainly involve an effort to maximize the *flexibility* of electricity supply to respond to unpredicted demand developments as they are occurring. This could include an attempt to reduce the time-lag between the decision to proceed with a new capacity addition and the in-service date of the new facility, by streamlining the regulatory and planning processes, or perhaps by utilizing less capital-intensive generating facilities (such as combined cycle plants or natural gas-fired units) that take less time to construct than large hydroelectric stations and nuclear power plants. Alternatively, utilities may use the opportunities provided by electricity trade to maximize their flexibility to deal with unplanned demand changes, by either selling surplus power to external customers in the event of a demand downturn, or calling

back firm exports (subject to contract provisions) to supply the domestic market if demand growth is faster than expected.

This overview of the structure and uncertainty of Canadian electricity demand has provided us with a very basic introduction to the various issues that must be overcome in trying to analyze and forecast electricity demand. In the rest of this chapter, two illustrative demand scenarios are developed to estimate the size and timing of new capacity additions in Canada's electric power industry during the 1990s.

2.3 Capacity Additions Motivated by Internal Demand

This section develops an estimate of the amount of new generating capacity required in the 1990s to meet growth in Canadian electricity demand. The section starts with a summary description of the existing resource base of Canadian utilities. It then introduces a base scenario of future demand growth in Canada compiled from the demand forecasts of the major Canadian electric utilities.⁴ Comparing this demand forecast to the capacity of existing generating facilities allows us to develop an estimate of the amount of new capacity that will be required to meet expected demand.

For the purposes of this discussion, growth in domestic electricity demand is considered separately from additional demand that certain utilities may choose to service in the interprovincial or international export markets. Utilities in several Canadian provinces--especially British Columbia, Manitoba, Quebec, New Brunswick, Nova Scotia and Newfoundland--are aggressively pursuing possible long-term sales of firm power to the United States or, in some cases, to other provinces. These external marketing opportunities could have a dramatic effect on the rate of addition of new generating capacity in each of these provinces.

For now, however, we will examine only that share of new capacity that is likely to be necessitated by the growth of domestic demand. We adopt this approach for two reasons. In most cases, these export opportunities have yet to be fully confirmed, and it is unlikely that all or even most of them will eventually be carried to fruition. It would therefore be premature to forecast capacity development schedules on the basis of export opportunities that may or may not be realized. Secondly, even in those cases where the export sale is reasonably assured (such as Manitoba's upcoming sales of power to

Ontario and to the United States), it is useful for analytical purposes to separately examine the two major sources of demand--indigenous and external--in order to describe how utility construction programs have been impacted by their export marketing efforts.

In Section 2.5 of this chapter, these export opportunities are incorporated into the analysis, and their impact on the overall capacity additions expected in Canada is considered.

2.3.1 The Existing Supply/Demand Balance

The key indications of the supply and demand situation prevailing in each province are summarized in the provincial electricity vignettes contained in Volume II; in the present discussion, we will report only the most aggregate and general measures. Total available generating capacity in Canada⁵ is presently just under 100 000 MW, an increase of almost 25 percent over the amount existing in 1980. Over half of this capacity is found in Ontario and Quebec. British Columbia, Newfoundland and Alberta are the next largest electricity producers, with a total of almost 25 000 MW of capacity between them.

The majority of Canadian provinces still enjoy reserve margins--that is, spare generating capacity as a share of peak demand--well in excess of 20 percent, indicating that the abundant excess capacity built up during the 1970s and early 1980s still has yet to be fully worked off. The major exception to this is Quebec, with an estimated reserve margin of just 9 percent. With a generating system based almost exclusively on hydroelectric stations, which are constrained more by energy shortages than by peak capacity, Quebec's network is able to function with a reserve margin much lower than would be needed in most other provinces as hydro units have inherently higher reliability than thermal units. Nevertheless, Quebec's generating reserve would have to be classified as minimal. Other provinces facing relatively tight supply/demand balances include Saskatchewan, Nova Scotia, Ontario and British Columbia. The average reserve margin for Canada as a whole is about 24 percent.⁶

Electricity consumption in Canada totalled 461 320 GW.h in 1988. Again, Quebec and Ontario were responsible for 66 percent of this total, followed by B.C. and Alberta, which accounted for slightly over 20 percent of total consumption. Annual energy demand growth averaged 4.9 percent per year in the 5-year period ending in 1987--faster than most forecasts had expected. In certain provinces, demand

growth was considerably higher, including New Brunswick (with a 7.9 percent average annual increase over the 5 years), Quebec (6.1 percent per year) and Alberta (6.1 percent). Reasons for this stronger-than-expected electricity demand performance include the strong record of economic growth in Canada, real electricity prices that were stable or declining in most provinces and the continued penetration of electricity into new or competitive markets, such as home heating and industrial power.

2.3.2 Base Demand Growth Scenario

In light of this recent strong demand growth, what type of demand trend can be expected through the 1990s? In order to develop our description of capacity additions in Canada, we have assembled a forecast of demand growth in Canada over the period 1989 to 2005. This forecast is based on the demand forecasts that utilities themselves have prepared for their own planning purposes. Utility demand forecasts for each province are assembled and a Canada-wide total is produced.⁷ This "base" demand forecast results in an average Canadian growth rate of 2.4 percent per year over the 12 years leading up to the end of the century. Table 2.2 provides a summary of the utilities' demand forecasts for each province, together with the subsequent Canada-wide average.

2.3.3 Expected Capacity Additions

Having described the existing generating facilities of Canadian utilities and two scenarios of future demand growth, we can now calculate an estimate of future capacity additions. To do this, we must make an assumption about the minimum capacity reserve margin that each provincial utility must maintain. This minimum reserve will depend on a complex interaction of a variety of factors, including the size of each provincial electric system, the type of generating facilities on stream and their maintenance requirements, and the size of the largest generating units relative to the demand placed on the system as a whole. Based on a set of the estimated minimum reserve ratios for each province,⁸ peak demand is multiplied by the province-specific reserve requirements to obtain a measure of required capacity in each province. This measure is then compared to the existing generating capacity in each province, to obtain an estimate of the amount of new generating capacity that will be needed by a chosen date in the future.⁹

TABLE 2.2
SUMMARY OF PEAK POWER DEMAND FORECASTS
1988-2000^a

Province	Average Peak Power Growth Rate (%)	
	Base Demand Scenario (utilities)	High Demand Scenario (utilities)
B.C.	2.56	3.65
Alberta	5.20	6.31
Saskatchewan	2.86	3.96
Manitoba	1.91	2.99
Ontario	1.52 ^b	2.60 ^b
Quebec	2.33	3.42
New Brunswick	2.87	3.96
Nova Scotia	3.40	4.50
P.E.I.	1.78	2.87
Newfoundland	2.49	3.58
N.W.T. & Yukon	0.56	1.63
Canada Average	2.41	3.50

SOURCE: Energy, Mines and Resources Canada, Policy Studies Group, 1989.

^aSee text for explanation of high case calculations.

^bGrowth rate assumes that aggressive demand-side management and non-utility generation defer requirements for conventional generation. Both Ontario Hydro and the Ontario Ministry of Energy believe that actual load growth is more likely to be closer to the high demand scenario.

This calculation is made more complicated by the fact that many utilities in Canada are already in the midst of construction programs that are certain to bring on new electric generating capacity during the period of our forecast's horizon. These future capacity additions that are already committed must be incorporated into the analysis, in order to focus on the additional *uncommitted* projects that utilities will have to undertake. These committed construction projects--which include facilities such as Manitoba's Limestone dam and Ontario's Darlington nuclear power plant--are listed in Table 2.3. We estimate that a total of just over 14 500 MW of new capacity will be in place by the year 2000, *resulting from generation projects that have already been initiated by the various utilities.*¹⁰

To gain an estimate of additional, not-yet-committed capacity requirements, these committed projects are added to existing capacity in the respective years that they are completed. This measure of existing plus committed capacity (referred to as "committed capacity" in the tables) is then compared to the required capacity associated with each of the two demand scenarios. The difference between the two provides a measure of the estimated surplus or deficit in generating capacity existing in each province. The deficit existing in the year 2000 can be interpreted as the amount of new capacity that must be in place by the end of the century. The right-hand side of Figure 2.3 provides a visual interpretation of this methodology.

The numerical results of this forecast of future capacity requirements are presented in summary in Table 2.4 (see Volume II, Appendix C for the derivation of the numbers presented). For each scenario, the tables in Volume II provide expected peak demand, the capacity that would be required to meet that peak demand (assuming the maintenance of the minimum reserve ratio in each province) and the new capacity above and beyond existing and committed projects that must be brought on-stream by any given year. The year in which the capacity surplus/shortage column turns negative is the year in which the first new, uncommitted capacity must be completed. The year in which the forecast reserve margin falls below the minimum level required in each province is the year in which the first uncommitted capacity addition must be completed in order to maintain the generating reserve at an acceptable level.¹¹

For Canada as a whole, in the base demand scenario, we expect that a total of just over 9200 MW of new capacity will be required by the end of the century. Recall that this is in addition to the 14 500 MW of capacity that will be brought on-stream from

TABLE 2.3

FORECAST INCREASES IN GENERATING CAPACITY
FROM COMMITTED PROJECTS

Province		Project	Capacity
British Columbia	1995	Alcan purchase agreement	520 MW
	1998	Columbia R. benefits ^a	100 MW
	1999	Columbia R. benefits ^a	500 MW
	2003	Columbia R. benefits ^a	500 MW
Alberta	1989	Genesee 2	406 MW
	1990	Sheerness 2	380 MW
	1991	Genesee 1	406 MW
Saskatchewan	1990	Two 50 MW peaking units	100 MW
	1992	Shand 1	300 MW
Manitoba	1990	Limestone 1-2	256 MW
	1991	Limestone 3-7	640 MW
	1992	Limestone 8-10	384 MW
Ontario	1989	Darlington 1-2	1 762 MW
	1991	Darlington 3	881 MW
	1992	Darlington 4	881 MW
Quebec	1989	Manic 5 PA	1 056 MW
	1992	La Grande 2A	1 900 MW
	1995	La Grande 1	1 310 MW
		Laforge 1	820 MW
		Brisay	380 MW
New Brunswick	1992	Return of Lepreau capacity ^b	230 MW
	1993	Belledune coal	400 MW
Nova Scotia	1991	Trenton coal	150 MW
	1992	Prince mine-mouth coal	150 MW
P.E.I.	None		
Newfoundland	1989	Hollyrood 2 (oil)	25 MW
	1990	Stephenville/Hardwood (peak)	108 MW
Yukon and N.W.T.	None		
Total			14 545 MW

SOURCE: Energy Mines and Resources Canada, *Electric Power in Canada, 1988* (Ottawa, Ontario: Minister of Supply and Services Canada, 1989).

^aAt British Columbia's discretion, this capacity already exists in the form of the increased generating capability of stations on the U.S. portion of the Columbia River which resulted from the construction in B.C. of three dams under the terms of the Columbia River Treaty. The capacity will be returned to B.C. Hydro in three stages, as 30-year agreements for the sale of this extra power begin to expire late in this century.

^bAs in the case of B.C.'s Columbia River capacity, this generating capability already exists, but has been committed to U.S. utilities in the form of a firm power export contract. By 1992, this contract will have expired, with control over the capacity reverting back to NB Power.

Figure 2.3
Methodology of Capacity Requirement Forecast

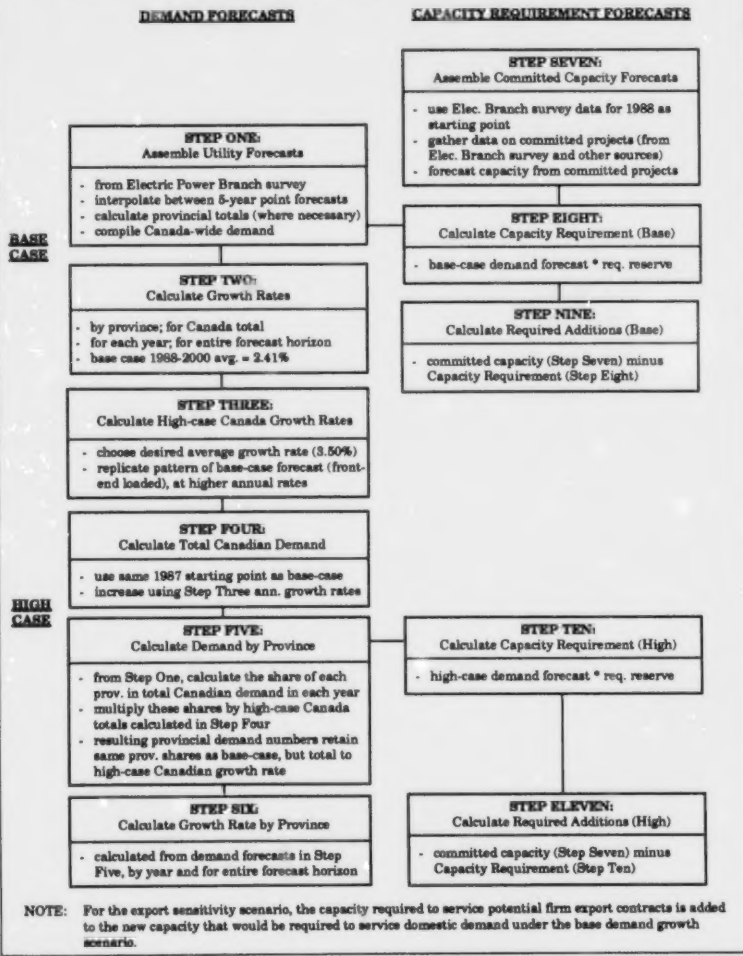


TABLE 2.4
UNCOMMITTED CAPACITY ADDITIONS
REQUIRED BY THE YEAR 2000^a
(MW)

Province	Base Demand Scenario	High Demand Scenario	Export Opportunities Included
B.C.	--	621	23
Alberta	4 253	6 021	4 253 ^b
Saskatchewan	434	932	434 ^b
Manitoba	--	227	360
Ontario	--	3 366	-- ^b
Quebec	3 691	9 329	7 541
New Brunswick	152	728	862
Nova Scotia	414	828	1 614
P.E.I.	57	81	--
Newfoundland	268	565	2 268
Yukon & N.W.T.	--	--	--
Canada Total	9 269	22 698	17 355

SOURCE: Energy, Mines and Resources Canada, Policy Studies Group, 1989.

^aThe required uncommitted capacity additions are based on peak demand growth which is appropriate for utilities that are not dependent upon significant hydro-generation. B.C. Hydro, for example, may be able to operate without uncommitted capacity additions and adequately meet the forecast peak. It may, however, have difficulty meeting its energy demands if the province experiences successive low-water years as is currently the case in Manitoba, Quebec and to a lesser degree British Columbia.

^bSame as in base case without exports.

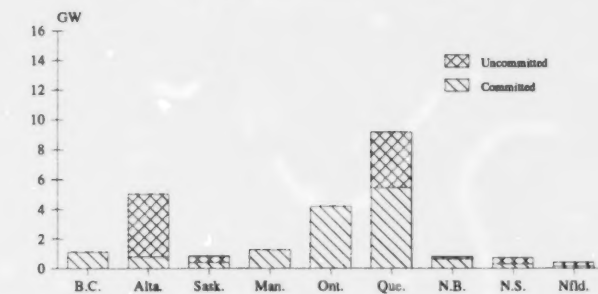
committed projects, resulting in total capacity additions of just over 23 700 MW. On a province-by-province basis (see Figure 2.4), the largest amount of uncommitted capacity will be required in Alberta; the province's fast-growing and energy-intensive industrial sector is the primary factor behind this large capacity requirement. Quebec also faces the prospect of large uncommitted additions to its generating resources (recall that Quebec also has more *committed* generation capacity under construction than any other province). In a number of provinces, including Manitoba and British Columbia, expected demand growth can be met *on the basis of existing and committed projects alone*, with no need to complete the construction of additional generation projects before the end of the century.

2.4 Sensitivity to Higher Demand Growth

The previous section has presented some estimates of the amount of new generating capacity that will be required in Canada in the next decade if demand growth outlined in Table 2.2. There is a widespread belief, however, based on the experience of the past 5 years, that Canadian utilities may have underestimated the future course of electricity demand in Canada. The base demand scenario described above expects annual demand growth in the range of 1.7 to 2.9 percent in the coming 5 years--considerably slower than the 4 to 5 percent growth rates that have been experienced in the recent past. In order to examine the sensitivity of future capacity requirements to higher-than-expected demand paths, we have constructed an alternative "high" demand scenario. This demand scenario is presented in Table 2.2. It assumes that average annual demand growth in Canada equals 3.5 percent per year over the same 12-year period--roughly one percentage point higher than in the base case described above. As a high demand case, this is a rather conservative scenario; it is certainly not inconceivable that electricity demand could grow at a rate significantly *faster* than that specified in this high case. Lower growth is also possible although this is not as broadly supported as is the probability of a higher load growth scenario.

In order to calculate province-by-province yearly demand estimates in the high case, the following methodology was adopted: the pattern of average Canadian demand growth implied in the base scenario (that is, higher growth in the near future, with slower growth towards the end of the century) was replicated in the high scenario, at higher rates of growth. This Canada-wide demand growth was then allocated to individual provinces in such a way that each province's share of total Canadian demand is the same in the high scenario as it

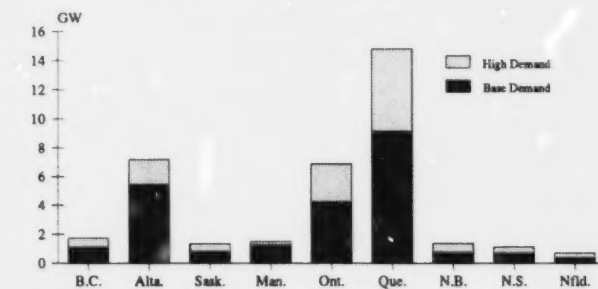
Figure 2.4
Capacity Additions by Province
Base Scenario - 1988-2000



SOURCE: EMR Canada.

NOTE: B.C. and N.B. committed capacity includes return of Columbia River and Pt. Lepreau capacity.

Figure 2.5
Capacity Additions by Province
High Scenario - 1988-2000



SOURCE: EMR Canada.

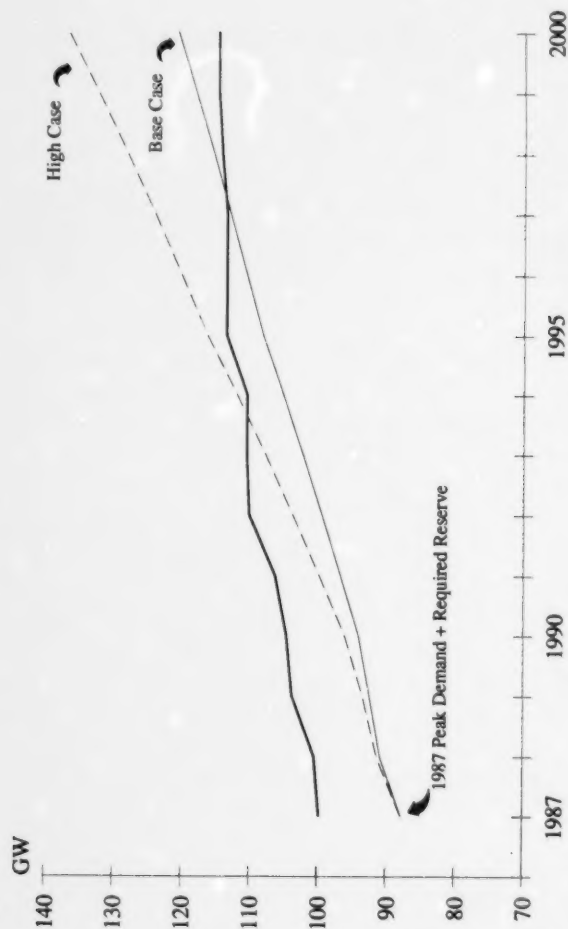
NOTE: Base demand includes already committed expansion projects.

was in the base scenario.¹² Province-specific annual demand growth rates can subsequently be calculated. For a visual description of this methodology, please refer to the left-hand side of Figure 2.3.

Following the same methodology that was utilized in the base case capacity additions calculations, we can compare these higher demand forecasts to the amount of existing and committed capacity in each province to obtain an estimate of the uncommitted capacity requirements faced across the country. In the high demand scenario, the amount of uncommitted required capacity more than doubles, from just under 9300 MW in the base scenario to just under 23 000 MW. Combined with the 14 500 MW that will be brought on-stream from committed expansion projects, this results in a total estimate of new capacity additions of over 37 200 MW by the end of the century.¹³ Province-by-province results are presented in Figure 2.5. Note once again that Quebec is responsible for a large share of the incremental capacity that would be required in the high scenario: the province's uncommitted capacity requirement is almost 6000 MW more in the high demand scenario than it was in the base case. Similarly, Ontario will face a need for large amounts of uncommitted capacity by the end of the century if the high demand scenario prevails--close to 3400 MW of capacity, roughly the size of a second Darlington megaproject, would have to be in place by the year 2000 if demand in the province follows the higher path (see notes to Table 2.2). All other provinces with the exception of Prince Edward Island (which imports most of its power) and the northern territories would have to add additional new capacity if demand follows the high scenario.

It is interesting to note that the difference between the uncommitted capacity additions required in the two cases is very large, even though there is only a moderate difference--one percentage point per year--between the two demand scenarios themselves. A *slight* increase in demand growth rates above what is currently expected by utilities is magnified into a *substantial* differential in terms of absolute future capacity requirements. The reason for this is illustrated in Figure 2.6. As mentioned above, many Canadian utilities are still working off the excess capacity that was constructed in the late 1970s and early 1980s, when economic slowdown and recession made the ambitious construction projects that were initiated in earlier years unnecessary. As shown at the left of the figure, existing capacity in Canada is roughly 10 000 MW more than would be required to meet peak demand plus the minimum reserve margin required in each province. This spare capacity, together with the capacity that will be

Figure 2.6
Generating Capacity and Reserve
Canada, 1987-2000



SOURCE: EMR Canada.

created as a result of already committed projects, will satisfy most of the demand growth that is *expected* by utilities between now and the end of the century. However, even a *slight* increase in the rate of demand growth pushes demand well beyond the range that could be satisfied by existing and committed generating projects. The additional capacity requirements in the high scenario (at the right of Figure 2.6) are some 2.5 times as great as those estimated in the lower demand case.

2.5 Sensitivity to Power Exports

In this section of the chapter, the expected capacity additions calculated for the base demand scenario in Section 2.3 are modified to take into account the substantial firm export opportunities currently being pursued by several Canadian utilities. This interest in firm, dedicated export contracts is a relatively new development in Canada's electricity industry. The high levels of electricity exports experienced in the 1980s were almost entirely based on short-term, interruptible contracts, and were often pursued by Canadian utilities as a means of alleviating the financial consequences of excess generating capacity. The new rush to sign up firm power contracts in the United States market is qualitatively different from the experience of the past two decades, in that it would involve the construction of generating facilities explicitly dedicated to the export market for the life of the export contract. No longer would export sales be seen as a potential lucrative supplement to domestic sales in times of off-peak demand or overcapacity. Rather, export markets are increasingly viewed by many Canadian utilities as a business opportunity in and of themselves, worthy of a self-financing, full-cycle commitment of resources.¹⁴ An expected serious shortage of generating capacity in the United States in the coming decades is the most important factor motivating many Canadian utilities to look south of the border for future revenues.¹⁵

Naturally, export plans of this nature will have an important effect on the capacity construction schedules of the various exporting utilities. For the purposes of this chapter, we have identified six provinces which can reasonably be considered to have access to a firm export market within the rest of this century: British Columbia, Manitoba, Quebec, New Brunswick, Nova Scotia and Newfoundland.¹⁶ In most of these cases, the export possibilities are oriented towards the United States. In some cases, such as Manitoba's sale of 200 MW of power to Ontario starting in 1998, or Newfoundland's possible sale of Lower Churchill power to Quebec, the trade would be interprovincial.

Either way, the construction of dedicated export facilities would add to the capacity requirements associated with demand growth indigenous to the province.¹⁷

The approach adopted by this discussion will begin with a brief inventory of the various firm export opportunities presently being considered by Canadian utilities. Subsequently, the consequences for capacity additions resulting from these opportunities will be described in detail.

2.5.1 Review of Export Opportunities

A summary of the size and timing of the most prominent firm, electricity export projects is provided in Table 2.5. The various projects range greatly in size, in technology, and in their degree of certainty, from relatively small but secure sales to long-shot megaprojects. A short description of the main prospects being pursued by each exporting province is provided below.

2.5.1.1 British Columbia

Electricity exports to the U.S. have long played an important role in the development of B.C. Hydro's electricity system, particularly since the signing of the Columbia River treaty almost 30 years ago which ushered in an unprecedented era of collaboration between the provincial utility and the utilities of the U.S. Northwest. The size of exports has varied tremendously from year to year, and the unit price earned by B.C.'s exports has been relatively low, due primarily to an inability to obtain firm access to transmission lines to the major population centres in California and other states. As a result, almost all of B.C.'s exports have been interruptible sales. It is hoped that the Free Trade Agreement, which contains specific provisions allowing for more open access to the transmission facilities of the Bonneville Power Administration (BPA), together with the upcoming expiry of the 30-year power sales that resulted from the Columbia River treaty, will enhance B.C.'s export position with the United States.

Future export opportunities now are a centrepiece of the B.C. government's plan to rely increasingly on private capital to construct new generating facilities. A new subsidiary of B.C. Hydro, POWEREX, has solicited proposals from private power producers for between 400 and 600 MW of privately built, export-dedicated generating capacity.¹⁸ It is hoped that the first of these projects could begin producing power for export by 1996. The provincial government has yet to make its selection of the specific project proposals that will be

Table 2.5
List of Potential Firm Electricity Exports
and their Proposed Starting Dates

Year	B.C.	Manitoba	Quebec	New Brunswick	New Scotia	Newfoundland	Canada MW
1989							0
1990							0
1991							0
1992							230
1993							600
1994							200
1995							1270
1996							760
1997							1060
1998							1100
1999							1300
2000							2800
2001							0
2002							0
2003							500
2004							0
2005							0
Total	1000	700	3500	530	1200	2000	9630

SOURCE: Energy, Mines and Resources Canada.

given the green light. Possible choices include mine-mouth, coal-fired stations at Balmer or Fording River, or the privately-financed development of the Murphy Creek site on the Columbia River.

The largest electricity sale by British Columbia could prove to be a renewal of the agreement between B.C. Hydro and BPA regarding B.C.'s share of the downstream benefits of the Columbia River Treaty. These benefits resulted from the increased generation capability of generating facilities in the U.S. that followed the construction of three dams on the Columbia River in British Columbia. These dams regulate the flow of the Columbia River in order to maximize the generating potential of downstream facilities. The downstream benefits were split between B.C. and the United States. B.C.'s share, totalling 1100 MW, was sold in a 30-year firm contract, in three stages beginning in 1968 when the first of the three upstream Columbia River dams came into operation. Ownership of this power will revert back to B.C. Hydro over a 6-year period starting in 1998. The B.C. government has indicated an interest in reselling this capacity to the U.S. utilities if favourable terms can be arranged.¹⁹

2.5.1.2 Manitoba

Manitoba Hydro has attempted to break into the firm export market on the strength of the massive hydroelectric resources of the northern Nelson River. The 1280-MW Limestone project, now nearing completion, was accelerated given the potential for export sales. So far, two major firm export deals have been arranged: a 500-MW power sale to Northern States Power Company of Minneapolis, covering the period 1993-2005; and a 200-MW firm sale to neighbouring Ontario between 1998 and 2003.²⁰ The marketing arm of Manitoba Hydro had been aggressively pursuing further export opportunities, in the hope that the construction of a 1300-MW station on the Nelson River at Conawapa could be similarly accelerated. At the time of writing, it appears that a firm export contract to Ontario which would warrant the construction of Conawapa is very likely. The contract is expected to provide Ontario with about 1000 MW of firm power over 20 years.

2.5.1.3 Quebec

Although Quebec is a net importer of electricity due to its massive imports of power from Labrador's Churchill Falls development, the province is also Canada's most ambitious exporter of power to the United States. In recent years, the bulk of Quebec's exports have been interruptible, but Hydro-Quebec has more recently adopted

a strategy to accelerate the construction of new hydroelectric facilities in order to serve the export market on a firm basis. The utility's current goal is to sell 3500 to 4500 MW of firm power to external markets by the year 2000 (supplemented by another 800 MW of off-peak seasonal sales).²¹ One major component of this project seems to have fallen into place: a sale of 1000 MW of firm power to the New York State Power Authority beginning in 1995.

The remaining segments of Hydro-Quebec's export strategy are not nearly so certain. A contract for the sale of 300 MW of firm power to Central Maine Power was cancelled by U.S. regulators early in 1989, because of their belief that conservation and cogeneration provided more economic domestic supply options than imports of power from Quebec. A contract with the Vermont Joint Owners for another 450 MW of firm power (250 of which is optional) has been signed and is now awaiting state approval and then federal (Canada) approval. A contract has been signed with the New York Power Authority for the seasonal sale of 800 MW of power during the summer months and has received approval from the National Energy Board. But like other off-peak seasonal sales, this would not affect Hydro-Quebec's construction schedule. To date, therefore, Hydro-Quebec has signed up at most only 1450 MW of its minimum target of 3500 MW external firm power sales. The utility hopes to make up the remainder of its target through further sales to New York, other New England states and possibly to Ontario. Barriers to this marketing blitz include, most notably, environmental concerns regarding the construction of further transmission corridors to the United States.

Hydro-Quebec's external market strategy is based on the notion of prebuilding generating capacity for the export market, and then reallocating the facilities to the service of domestic customers when provincial demand growth warrants. Utility officials suggest that the construction of new northern megaprojects could be advanced by 10 years by accessing lucrative export markets in the United States. This would provide macroeconomic benefits to Quebec resulting from the large investments in new facilities, and the revenue from export sales could help to pay for the cost of hydroelectric projects that will later be used to meet demand within Quebec. Most of the contracts with U.S. customers are being signed for periods of 15-20 years or longer, however, so the export-motivated facilities will not be automatically available at the moment they are needed to service domestic demand. This suggests that Hydro-Quebec may have to advance the

construction of other hydroelectric sites to meet rapidly-growing internal demand until the contracts with export customers have expired.

2.5.1.4 New Brunswick

Measured by the unit revenue generated by its electricity sales to the United States, New Brunswick has been Canada's most successful electricity exporter. This is primarily the result of a larger proportion of New Brunswick's export sales being arranged through higher-priced firm contracts than is the case with other provinces. On average, over 40 percent of New Brunswick's exports over the past 5 years have been firm sales, compared to average Canadian levels of less than 30 percent. A major component of these firm sales has been the dedication to firm export service of roughly one-third of the capacity (230 MW) of the Point Lepreau nuclear power station. This contract expires at the end of 1991, at which time the capacity will revert back to the service of domestic customers.

It is likely, however, that the provincial utility, NB Power, will resell the power from this portion of the Point Lepreau station to utilities in New England. This renewal of firm exports from the station would require the accelerated construction of other generating facilities to serve the domestic market, which has been the fastest-growing in Canada over the past 5 years. In addition to the resale of Point Lepreau power, New Brunswick has also offered up to 400 MW of firm power from proposed coal-fired stations in the province to the New England utilities. These plants could be completed as early as the middle of the next decade.²²

2.5.1.5 Nova Scotia

This province has been frustrated in its attempts to win access to U.S. electricity markets by an inability to negotiate transmission access through neighbouring New Brunswick. The ambitious Bluenose project, however, hopes to solve this problem with the construction of a 400-kilometre underwater transmission cable directly from Yarmouth, Nova Scotia to Massachusetts.²³ This cable would deliver up to 1200 MW of power from four new, export-dedicated coal-fired generating stations at Sheet Harbour, which would come on-stream over a 4-year period leading to the end of the century. The project faces some uncertainties regarding the technology of the under-sea cable (which would be the world's longest) and the environmental consequences of new coal-fired generating facilities.

2.5.1.6 Newfoundland

Newfoundland, too, has long sought to connect the untapped hydroelectric resources of Labrador to lucrative markets in the United States or in Central Canada. The problem of transmission access, however, is a formidable barrier, and to date negotiations with neighbouring Quebec have proven unsuccessful. Current proposals would see the development in the late 1990s of generating stations at Gull Island and Muskrat Falls (with a total potential of some 2400 MW), together with the addition of a twelfth, 500-MW generating unit at the Churchill Falls project. A share of this new power (perhaps up to 800 MW) would be delivered to Newfoundland via an underwater transmission connection at the Strait of Belle Isle, satisfying the island's foreseeable power requirements for at least 20 years. The remainder--some 2000 MW of surplus power--would be sold for export.²⁴ This may involve a wheeling agreement with Quebec, allowing the power to be delivered to the United States or Ontario. More likely, it would involve a purchase and resale agreement with Quebec, in which Hydro-Quebec buys the power in bulk and resells it to its own domestic and export customers. This project is also subject to immense economic and political uncertainties.

2.5.2 Effect on Capacity Additions

This brief inventory of firm export opportunities reveals a great variety of approaches to export power marketing amongst the various Canadian utilities. Some (like British Columbia or Nova Scotia) view export opportunities as a more-or-less separate profit centre of their businesses, with independent export-dedicated facilities. Others, including Manitoba and Quebec, see power exports as an opportunity to advance the construction of generating projects that would otherwise be delayed for several years awaiting the growth of domestic demand to make them viable. In the case of Newfoundland, access to an export market is fundamental to the further development of Labrador hydroelectricity, no matter how domestic demand grows in the future. These differences make it difficult to generalize with respect to the effect on future capacity additions of these export opportunities.

The third column of Table 2.4 displays expected future capacity requirements for each exporting province, if the export opportunities listed above are all taken into consideration. For Canada as a whole, the firm export opportunities add over 8000 MW to the amount of uncommitted capacity required by the year 2000. Uncommitted

capacity requirements would total just over 17 300 MW by the year 2000,²⁵ compared to the 9 300 MW expected in the base demand scenario without exports. Province-by-province results, as would be expected, vary with the scale of export opportunities available to each provincial utility. The relative size of provincial capacity additions, for both domestic demand (base scenario) and export markets, is illustrated in Figure 2.7.

2.6 Interpretation and Analysis

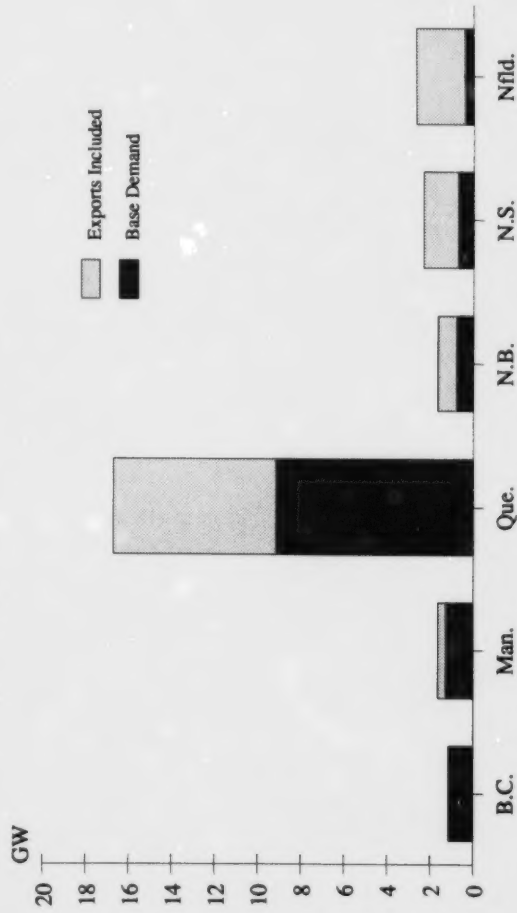
In the preceding sections of this chapter, we have provided some approximate estimates of the capacity additions that can reasonably be expected over the next 12 years in Canada, given two illustrative scenarios of domestic demand and an inventory of the various firm export opportunities being pursued by Canadian utilities. In this section we explore the significance of these results. First, the expected capacity additions are disaggregated into fuel-type categories, in order to develop an understanding of future changes in the generating mix of Canada's electricity system. Secondly, the varying time lines facing utilities with respect to the addition of new capacity are examined, in order to identify approximate "decision dates," that is, the dates by which utilities must have committed themselves to the construction of new facilities in order to have them completed and on-stream by the time they are required. Finally, we examine our estimates of future capacity additions in an historical context, comparing our expectations with the scale of capacity construction that has been experienced in previous decades, and thereby developing an understanding of the relative size and importance of probable investments by Canada's electric utilities in the 1990s.

2.6.1 Fuel Type

Of the approximately 14 500 MW of already-committed new capacity that will be made available to Canadian utilities over the remainder of the century, some 8500 MW (or about 60 percent) will be in the form of hydroelectric facilities. Most of the remaining committed projects are split between nuclear power units (3750 MW, more than 25 percent) and coal-fired plants (less than 1800 MW, or 13 percent). A small number of oil-fired generating units and gas turbines (primarily for peaking purposes) contribute another 250 MW to the total.

The fuel mix that will be reflected in expected but uncommitted future capacity additions is, naturally, much harder to

Figure 2.7
Capacity Additions by Province
Exports Included, 1988-2000



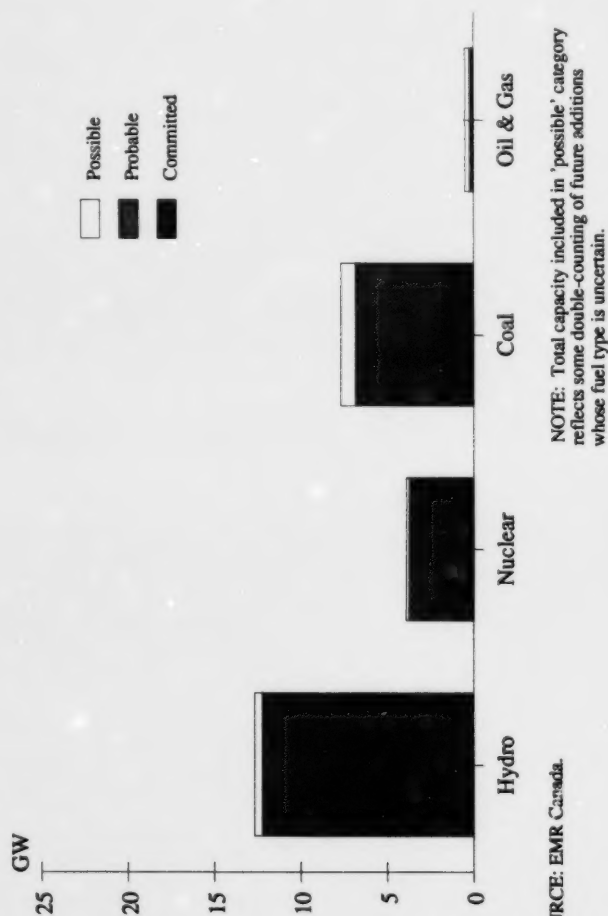
SOURCE: EMR Canada.
NOTE: Base demand includes already
committed expansion projects.

calculate. In a number of provinces, utilities have a variety of fuel options available to them in their planning of future projects. It is not possible for us to predict what particular fuel mix decisions will be made, as these decisions will be dependent on a complex combination of economic, political, technological and environmental factors. It is possible, however, to sketch in broad terms the general direction that the fuel mix of Canadian generating capacity is likely to take in the coming decade.

In a few provinces, the choice of fuel for future generating projects is almost certain. In British Columbia, Manitoba and Quebec, for example, it is virtually assured that capacity additions through the rest of this century and beyond will take the form of hydroelectric facilities.²⁶ Similarly, future capacity additions in Alberta and Nova Scotia will likely be dependent on coal-fired generation; to a somewhat lesser extent, this is also true of Saskatchewan, although there remains some undeveloped hydroelectric capacity in this province that could be developed by future projects, and even the possibility of a turn to nuclear power. The only provinces that face a significant degree of uncertainty in terms of future fuel choice are Ontario (primary choice between coal or nuclear, with natural gas or firm imports as subsidiary options), New Brunswick (coal, nuclear or heavy oil), and Newfoundland, whose on-island facilities will almost certainly be oil-fired, but which may gain access to Labrador hydro power if the necessary transmission facilities are constructed.

Based on this province-by-province survey, a general idea of the fuel mix of future capacity additions can be assembled as illustrated in Figure 2.8. A total in excess of 12 250 MW of hydroelectric capacity is almost certain to be added before the year 2000, based on already-committed projects and on future additions in Quebec;²⁷ depending on the fuel choice made in certain provinces, this amount could be somewhat higher. It is virtually inconceivable that any nuclear power plants not yet committed could be brought on-stream by the end of the century; therefore, we expect that the total new nuclear capacity made available by the year 2000 will be limited to the two committed projects (the Darlington station in Ontario, and the return of 230 MW of New Brunswick's Point Lepreau capacity).²⁸ A large amount of new but not yet committed coal-fired capacity is likely to be brought on-stream during the 1990s, mostly in Alberta. We expect that a total of about 7000 MW of new coal-fired capacity, just under 2000 MW of which is already committed, will be completed by the end of the century. Another 1000 MW could be added, for a total of almost

Figure 2.8
Capacity Additions by Fuel Type
Base Scenario, Canada, 1988-2000



8000 MW, if New Brunswick and other provinces opt for coal plants in their respective planning decisions. Finally, we expect that less than 500 MW of other thermal capacity (primarily oil and gas) will be added by the year 2000 (250 MW already committed).

Based on this scenario a rough estimate of Canada's future generating mix can be developed. Using the fuel mix figures assembled above, we expect that hydro's share of total capacity will stay roughly constant, at about 58 percent, for the remainder of the century. The share of coal-fired capacity in the total generation mix will increase slightly, to about 19 percent, primarily at the expense of oil- and gas-fired facilities. The completion of the Darlington plant will be enough to maintain nuclear power's share of total capacity constant at about 12 percent.

2.6.2 Decision Dates

Much of the uncertainty involved in electric utility planning arises from the long lead times involved in the construction of most types of generating facilities. A conventional coal-burning generating facility requires 3 or 4 years of construction time; a major hydroelectric facility 6 to 8 years; and a nuclear power plant anywhere from 6 to 8 years for a CANDU 3, to 10 years or more for a Darlington-sized megaproject. The various requirements needed to satisfy the regulatory process may add several years to these figures. This makes it very difficult for utilities to match their generating resources to the path of demand growth.

Utilizing this information, on the expected size and timing of required future capacity additions in the various provinces, together with our assumptions about fuel choice outlined in the preceding subsection, we can attempt to identify the key decision dates facing each provincial electricity system. In other words, we can estimate the year in which each utility has to make a decision to commit itself to one type of generation over another. These decision dates are summarized in Tables 2.6a to 2.6c for the base demand scenario, as well as for the two sensitivity cases: incorporating higher demand growth and the various export projects, respectively. As noted above, however, these decision dates should be regarded as "late-dates," as the regulatory process may add considerably to the time required to plan, approve and construct new electric generating capacity.

On the basis of the base domestic demand growth scenario, the data suggests that several provinces (including B.C., Manitoba and

TABLE 2.6a

DECISION DATE ANALYSIS:
FUTURE CAPACITY ADDITIONS
BASE SCENARIO

Province	Need Date	Likely Fuel Source	Lead Time	Implied Decision Date
British Columbia	--	Hydro	6-8 yrs.	--
Alberta	1992	Coal	3-4 yrs.	1988-1989
Saskatchewan	1995	Coal (Nuclear?)	3-4 yrs.	1991-1992
Manitoba	--	Hydro	6-8 yrs.	--
Ontario	2002	Nuclear/Coal (Import?)	4-12 yrs.	1990-1998
Quebec	1997	Hydro	6-8 yrs.	1989-1991
New Brunswick	1999	Coal/Nuclear/Oil	3-8 yrs.	1991-1996
Nova Scotia	1995	Coal	3-4 yrs.	1991-1992
P.E.I.	n.a.			
Newfoundland	1996	Oil/Coal	3-4 yrs.	1992-1993
Yukon & N.W.T.	n.a.			

SOURCE: Energy, Mines and Resources Canada, Policy Studies Group, 1989.

TABLE 2.6b

DECISION DATE ANALYSIS:
FUTURE CAPACITY ADDITIONS
HIGH SCENARIO

Province	Need Date	Likely Fuel Source	Lead Time	Implied Decision Date
British Columbia	1998	Hydro	6-8 yrs.	1990-1992
Alberta	1990	Coal	3-4 yrs.	1986-1987
Saskatchewan	1993	Coal (Nuclear?)	3-4 yrs.	1989-1990
Manitoba	1999	Hydro	6-8 yrs.	1991-1993
Ontario	1997	Nuclear/Coal (Import?)	4-12 yrs.	1985-1993
Quebec	1993	Hydro	6-8 yrs.	1985-1987
New Brunswick	1996	Coal/Nuclear/Oil	3-8 yrs.	1988-1993
Nova Scotia	1994	Coal	3-4 yrs.	1990-1991
P.E.I.	n.a.			
Newfoundland	1995	Oil/Coal	3-4 yrs.	1991-1992
Yukon & N.W.T.	n.a.			

SOURCE: Energy, Mines and Resources Canada, Policy Studies Group, 1989.

TABLE 2.6c

DECISION DATE ANALYSIS:
FUTURE CAPACITY ADDITIONS
EXPORTS INCLUDED

Province	Need Date	Likely Fuel Source	Lead Time	Implied Decision Date
British Columbia	2001	Hydro? Coal?	4-8 yrs.	1993-1997
Alberta	n.a.			
Saskatchewan	n.a.			
Manitoba	1998	Hydro	6-8 yrs.	1990-1992
Ontario	n.a.			
Quebec	1996	Hydro	6-8 yrs.	1988-1990
New Brunswick	1994	Coal/Nuclear/Oil	3-8 yrs.	1986-1991
Nova Scotia	1996 ^a	Coal	3-4 yrs.	1992-1993
P.E.I.	n.a.			
Newfoundland	1999 ^a	Hydro	6-8 yrs.	1991-1993
Yukon & N.W.T.	n.a.			

SOURCE: Energy, Mines and Resources Canada, Policy Studies Group, 1989.

^aNew capacity to meet domestic demand will be required before these need dates for potential firm exports. Since the proposed exports in both Nova Scotia and Newfoundland would be supplied from dedicated export facilities, their decision dates have been presented independently of those resulting from domestic demand growth, and are therefore invariant to the high case demand forecast.

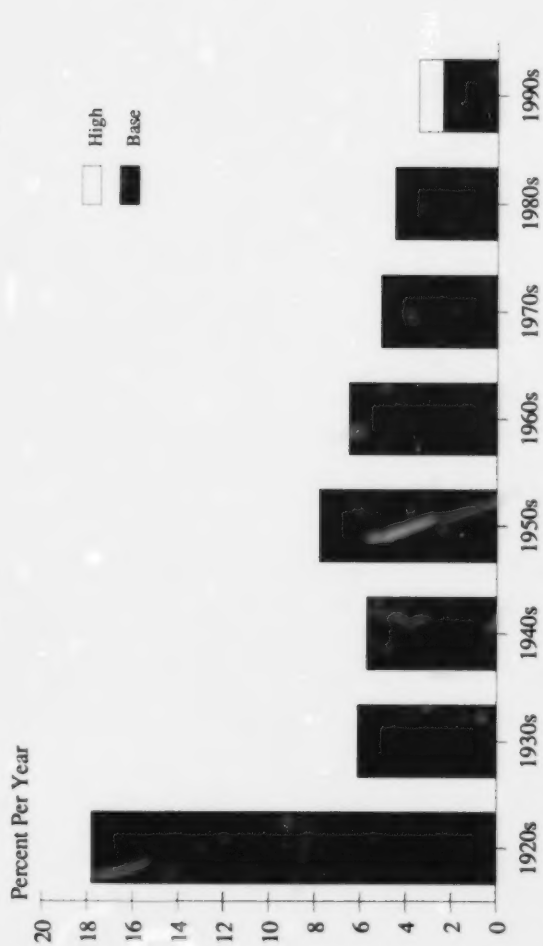
New Brunswick) would have the luxury of waiting well into the 1990s before committing themselves to the construction of generating facilities above and beyond those which are already existing or committed.²⁹ Nova Scotia and Saskatchewan would have to make a decision early in the 1990s, while Quebec and Alberta need to select future generating options immediately. If the high demand scenario were to prevail, however, then the decision dates for all provinces are pushed forward significantly. Only Manitoba, British Columbia and New Brunswick would have the option of waiting until the early 1990s to select their next expansion of generating facilities; all other provinces would face a need to commit themselves to new projects by 1990 at the latest.

The incorporation of firm export projects further complicates the planning process for those provinces considering entry to firm power markets. Quebec and New Brunswick would need to commit themselves to new construction projects immediately if they are to proceed with planned firm exports.³⁰ British Columbia and Manitoba will need to decide on additional hydroelectric projects much sooner than would have been the case without the firm exports (although in B.C.'s case, the option of coal-fired export plants, with their shorter construction periods, considerably stretches out the decision period). For Nova Scotia and Newfoundland, the firm exports would be generated in export-dedicated facilities that can be considered more-or-less separate from the rest of their respective provincial systems. In this case, the two provinces face *two* sets of decision dates: one for domestic service facilities (needed relatively urgently in both cases) and one for the export plants (which would have to be committed by 1994 for both provinces).

2.6.3 Historical Comparison

It is useful to compare the size of expected capacity requirements over the next decade, to the rate of new capacity construction that has been experienced in the Canadian electricity industry in previous periods. As illustrated in Figure 2.9, the average annual growth in electricity demand expected in Canada over the rest of this century—even in the higher of the two demand scenarios—is quite modest by historical standards. A generally slower rate of economic growth by historical standards, increases in energy efficiency, and an exhaustion of the potential electricity demand growth resulting from penetration into new energy markets such as home heating, combine to suggest that the rate of future demand growth will generally be slower than has been experienced even in the recent past.

Figure 2.9
Electricity Demand Growth by Decade
Canada, 1920-2000



SOURCE: Historical Statistics of
Canada, Electric Power in Canada.

Unfortunately, this does not mean that the electricity industry will face less supply pressure as a result. Because the size of Canada's electricity system has increased so greatly, even modest rates of demand growth will be reflected in relatively large absolute requirements for new generating capacity. As illustrated in Figure 2.10, our base demand scenario (including firm export opportunities) would result in the addition of some 3000 MW of new capacity per year between now and the year 2000--more than in any period of Canadian history, with the exception of the 1970s. If, on the other hand, demand growth were to follow the higher scenario, the system would require average increases in generating capacity of nearly 5000 MW per year--more than twice the rate of capacity additions experienced so far during the 1980s. This massive increase in the generating base of the industry will require a huge boost in investment by electric utilities in new facilities, from the figures of \$5 to \$6 billion per year experienced during the mid-1980s, to perhaps as high as \$12 to \$15 billion per year. The effects of this sharp increase in utility investment on both the Canadian economy and on the financial situation of the utilities themselves will certainly be significant.

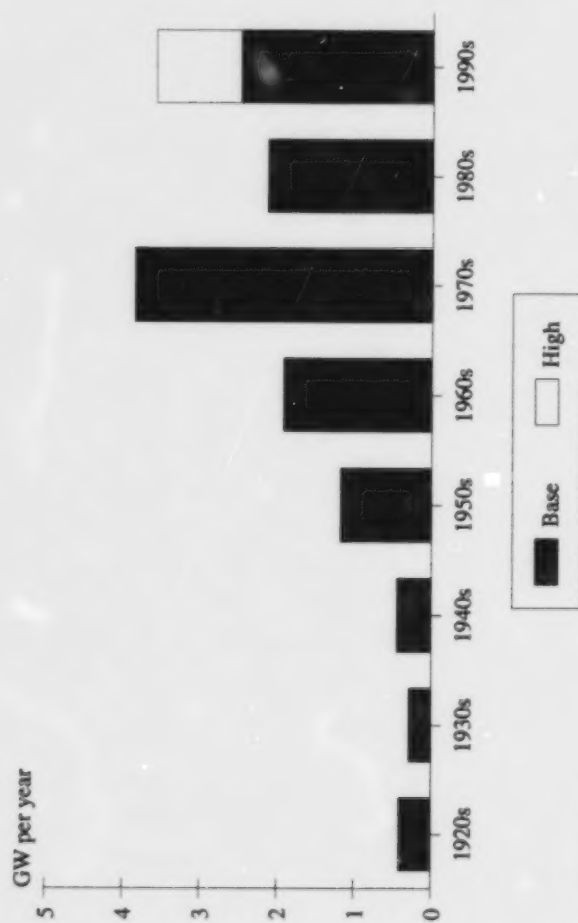
2.7 Conclusions

The purpose of this chapter has been to attempt to develop a general idea of the scale of future capacity requirements facing Canadian electric utilities. We developed two scenarios of domestic demand growth--one based on the utilities' own demand forecasts, the other reflecting an expectation of slightly faster demand growth. We reviewed the various firm export opportunities being cultivated by certain Canadian utilities, and examined the effect that these could have on the total demand for Canadian electricity. We then compared these expectations of future demand to the existing generation base of the industry, in order to roughly estimate the amount of new capacity that utilities must commit themselves to completing by the end of the century. The implications of these findings for the future fuel mix of the Canadian electricity network, for the planning process of utilities, and for the rate of utility investment were briefly explored.

More specifically, the three most important of our findings can be summarized as follows:

1. **Amount of New Capacity:** The amount of new generating capacity that will be required by Canadian utilities through the rest of the century will be much greater than the rate of new facility construction that has been experienced in the last decade. Depending on

Figure 2.10
Yearly Capacity Additions
Canada, 1920s-1990s



SOURCE: EMR Canada.

the exact demand forecast that is accepted, annual new capacity requirements may be greater than at any time in Canadian history, despite a generally slower rate of domestic demand growth.

2. **Sensitivity to Demand:** The rate of capacity addition is very sensitive to assumptions regarding domestic demand growth. Total capacity additions required by the year 2000 are more than twice as large in the high demand scenario (3.5 percent average annual growth) than in the base scenario (2.4 percent average annual growth).
3. **Sensitivity to Exports:** The amount of new capacity required in several key provinces could be considerably increased by the successful negotiation of various firm power export proposals currently being promoted by a number of Canadian utilities. If all of these export projects came to fruition, the amount of new capacity required by the end of the century would be as much as 8 000 MW greater than if capacity was built to service Canadian demand only.

In addition to these key findings, we also developed a number of more specific and more tentative conclusions regarding the location, fuel-type and timing of capacity additions:

4. **Location of New Capacity:** Quebec will require the most new generating capacity by the end of the century. Other provinces with major uncommitted capacity requirements include Alberta, New Brunswick, Nova Scotia and Saskatchewan.
5. **Future Fuel Mix:** The fuel mix of future capacity additions is likely to remain very similar to the existing resource base, with hydroelectric facilities accounting for just under 60 percent of all new capacity. The share of coal-fired generation will increase slightly by the year 2000, offsetting a fall in oil- and gas-fired capacity. The share of nuclear power will remain roughly constant.
6. **Timing of Construction:** The construction decision dates facing each provincial utility are highly uncertain, varying greatly with assumptions made regarding future demand growth, transmission availability, size and timing of firm exports, and the type of fuel chosen for new facilities. Based on domestic demand alone, British Columbia, Manitoba, and New Brunswick must commit to the development of new resources in the early-1990s. Other provinces will need to decide on new capacity additions very early in the next decade. The demand growth figures underlying our analysis

suggests that two provinces--Quebec and Alberta--need to commit to new capacity projects immediately.

It must be stressed that the figures presented here are in no way a *forecast* of the size and timing of future capacity additions in Canada. We have not attempted to select one particular demand scenario over another, nor to determine which export projects are likely to come to fruition. We have in essence only completed an exercise in sensitivity analysis, and our findings are important, if tentative.

If demand grows at the rate presently forecast by utilities, then we can expect a requirement for a certain amount--some 9200 MW--of new, uncommitted capacity by the year 2000. *If* demand grows at a faster rate, that capacity requirement more than doubles. And *if* the various firm export proposals being pursued by several provinces come to fruition, the need for new capacity is both increased and made more imminent. In *all* of the scenarios that we developed, the resulting rate of construction of new capacity in Canada proves to be considerably greater than that which has been experienced in the past decade. This will make it even more imperative for utilities and policy makers to resolve the various fundamental issues that currently complicate the planning process--questions such as demand management, non-utility generation, electricity trade issues and the environment.

Footnotes

¹For a more detailed discussion of the current supply/demand balance in each province, please refer to the provincial vignettes contained in Volume II.

²For a more detailed description of this evolution in the nature of electricity demand, see the historical summary contained in Volume II.

³National Energy Board, Canadian Energy Supply and Demand, 1987-2005 (Ottawa, Ontario: Minister of Supply and Services Canada, September 1988), pp. 44-50. This report provides a useful summary of the various technological changes experienced in Canadian industry and their effects on energy and electricity consumptions.

⁴This case will be referred to as the base scenario, to differentiate it from the high demand scenario introduced in Section 2.4.

⁵Excluding private industrial generating facilities, which are not included in the interconnected grids of the major utilities.

⁶Energy, Mines and Resources Canada, Electric Power in Canada, 1988 (Ottawa, Ontario: Minister of Supply and Services Canada, 1989), p. 33.

⁷These forecasts are submitted each year to the Energy, Mines and Resources Electricity Branch as part of an annual survey of Canadian electrical utilities. They are published annually in the Energy, Mines and Resources report, Electric Power in Canada.

⁸*Ibid.*, p. 27.

⁹Note that since the demand forecasts of the utilities extend to the year 2005, we have calculated required capacity additions up to that time. We are primarily concerned here with the evolution of the electricity industry through the 1990s; however, in our discussion we limit ourselves to those capacity additions likely to be constructed before the year 2000.

¹⁰Note that these committed capacity additions also include the return to Canadian control of existing generating capacity that has been committed to U.S. utilities through long-term firm power export sales. Specifically, this refers to the return of 230 MW of capacity from the Point Lepreau nuclear power plant in New Brunswick in 1992, and the return to British Columbia of 1100 MW of capacity resulting from the downstream benefits of the Columbia River treaty, over a 6-year period beginning in 1998. In both cases the capacity already exists, but they are excluded from the measurement of available capacity in Canada since they are dedicated to U.S. customers until the expiration of the respective agreements.

¹¹More detailed information on capacity additions expectation is provided in Tables C1 to C12 (Appendix C, Volume II). The

data in Table 2.4 assumes that the reserve margin in each province never falls below the minimum required level, and then calculates the amount of uncommitted capacity that must be constructed to keep the reserve margin above that minimum level.

¹²This methodology is similar to the approach followed by a study of future capacity additions in the U.S. electricity industry; see U.S. Department of Energy, Office of Policy, Planning and Analysis, Electric Supplies for the 1990s: Growing Reliance on Demand Management and Third-Party Suppliers, by Jeffrey Skeer (Washington, D.C.: Office of Policy, Planning and Analysis, U.S. Department of Energy, October 1988).

¹³These estimates are based on domestic demand growth only, and do not include capacity that would be required to meet potential firm export contracts.

¹⁴Note that this is not the first time in Canadian history that our electricity trade has focussed on firm exports to the United States. Most of the major hydroelectric installations constructed early in this century were built with the explicit purpose of serving a small number of bulk customers in the United States. Indeed, many of these early facilities were constructed by subsidiaries of U.S. utilities or major American manufacturing firms. See the historical overview contained in Volume II for more detail on the history of Canada-U.S. electricity trade.

¹⁵See Chapter 5, dealing with electricity trade, for a more detailed explanation of the motives and constraints that will likely govern Canada's future electricity trade, both with the United States and between provinces.

¹⁶This list is not exhaustive, but rather is simply an indication of the provinces which have the most advanced plans for firm exports. Ontario is traditionally a major exporter of electricity, but is excluded from this list because the province's tightening supply/demand balance ensures that future exports will be short term and interruptible. Alberta has made some preliminary studies of the possibility of wheeling power through British Columbia to U.S. Pacific markets, but at present the actual completion of such a project seems rather remote, for both economic and regulatory reasons.

¹⁷Although in the case of interprovincial trade, the firm export facilities would be deducted from the capacity requirements of the importing province.

¹⁸See Vancouver Province, April 6, 1989, p. 35.

¹⁹In the tables that accompany this chapter, the return of the Columbia River downstream benefits is treated as a committed capacity addition, since the capacity belongs to B.C. Hydro but is excluded from currently available capacity because of its 30-year sale to the U.S. utilities. Subsequently, the possible resale of this power is treated as a firm export, so that it can be considered on the same

footing with other firm export projects. This creates the slightly odd situation in which if these benefits are resold by B.C. Hydro, so that there is no net impact on B.C. Hydro's demand and supply circumstance, our listing of B.C.'s committed capacity and firm exports will nevertheless both increase by the amount of 1100 MW.

²⁰A third export contract, a 200-MW firm contract with Northern States in the summer months only, is excluded from this discussion because summer is an off-peak period for Manitoba's electricity system, and this sale will therefore not affect the timing of future capacity additions in the province.

²¹Hydro-Quebec, Hydro-Quebec Development Plan 1989-1991, Summary (Montreal, Quebec: Hydro-Quebec), pp. 7-8.

²²"NB Power Eyes New England Sales after Quebec Deal Fails," The Globe & Mail, January 13, 1989, p. B.9.

²³Chronicle Herald, March 9, 1989, p. 47.

²⁴"Peckford Wants Hydro Deal Sealed Before Commenting," The Evening Telegram, November 28, 1988, p. 1.

²⁵In addition to the 14 000 MW of capacity that will result from committed new generation projects by that time.

²⁶It is possible that one or more export-dedicated facilities in British Columbia could be coal-fired.

²⁷This estimate refers to the base demand scenario, including the firm export opportunities outlined in Section 2.4.

²⁸The one exception to this general rule might be the smaller CANDU 3 reactor (450 MW) being proposed for construction at Point Lepreau in New Brunswick; Atomic Energy of Canada claims that this smaller reactor could complete the entire planning and construction cycle in as little as 6 years, comparable to a hydroelectric facility.

²⁹Note that this result for Saskatchewan assumes that the first Shand generating station is completed according to schedule.

³⁰In Quebec's case, our analysis suggests that new projects must be committed immediately, regardless of whether the firm exports are confirmed or not.

³¹Including generation projects currently committed for construction but not yet completed.



Chapter 3

DEMAND MANAGEMENT

3.1 Introduction

Since the early 1970s, various economic, political, social, technological and resource supply factors have combined to change the electric utilities' operating environment and outlook for the future. Higher fuel costs have raised electricity prices and slowed economic activity, resulting in a reduction in the growth of demand for electricity. Escalating power plant construction costs have raised electric rates which, in turn, has sponsored adverse regulator and customer reaction. Today, many electric utilities are faced with the prospect of major capital requirements for new plants, significant fluctuations in demand and energy growth rates, and concern about consumer response to rising electricity prices.

As noted in the preceding chapter, as electricity demand continues to grow, ever larger blocks of electrical generating capacity must be added to the electrical grid. This constitutes a risk to electrical utilities and their ratepayers, as major increments of new capacity imply long construction lead times and early capital commitment. The long-term electricity forecasts supporting new capacity additions are subject to considerable uncertainty as many factors can influence the growth in electrical demand. Forecasts may turn out to over- or underestimate actual demand, which may in turn result in the utility being over- or under-built relative to actual calls on the electric power system. Moreover, capital cost and fuel cost uncertainty coupled with long planning lead times may obscure the most economic mix of supply options. The complexity of the planning process can further be exacerbated by changes in regulatory requirements, such as safety and environmental regulations and/or by a change in public attitudes and acceptance of generation options—e.g., public concern with global warming. In addition, planning for future electricity needs has been complicated by the development of non-utility sources of electricity generation (parallel or independent electric power).

Due to the significant risks associated with forecasting and planning for new power supply, some utilities have turned to efficiency improvements to better utilize the existing system and defer new

generation. Electric utilities are becoming more aware of the services that customers derive from their use of electricity and this has given them a better understanding of ways of affecting or "managing" load patterns.

In the past, economies of scale in electric power generation have prompted utilities to look toward increased capacity, rather than load management, to meet forecasts of demand growth. However, the magnitude of new capacity additions coupled with cost and planning uncertainties are forcing many utilities and regulators to think strongly about pursuing load management initiatives. Some analysts also suggest that when flexibility, safety, social and environmental impacts are accounted for, efficiency improvements look even more attractive than constructing new electric generating facilities.

The management of electricity consumption patterns has evolved over the years from simple load management to demand-side management (DSM), and more recently to "least-cost planning." Under this latter approach, all feasible conservation and demand-side resources are evaluated, along with new energy supply options, and ranked according to their cost effectiveness.

The least-cost approach was first adopted in 1980 in the U.S. Pacific Northwest region. Since then, at least 16 states have adopted least-cost policies and requirements ... for example, the Austin, Texas municipal utility, Northern States Power Company, and Southern California Edison Company have been able to reduce electricity use and peak demand by 0.4 to 1.4 percent per year by offering rebate incentives to purchasers of efficient appliances and other equipment. This represents a 20 to 40 percent reduction in the rate of electrical load growth. Utilities with rebate programs are paying only \$200 to \$300 per kilowatt saved, thereby acquiring savings at a fraction of the cost of new power supplies.¹

This chapter reviews the concept of demand-side management (DSM) and discusses some of the benefits and problems involved in its implementation. The latter portions of the chapter highlight its practice in Canada and the United States and refer to some recent recommendations supporting its future evolution in Canadian electric power planning.

3.2 DSM Defined

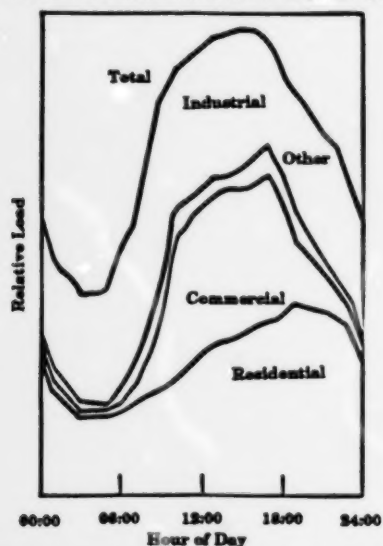
One of the basic principles underlying electric power development has been the notion that a power system will supply its customers with whatever amount of power is required, at whatever time they desire. In exercising their preferences, customers have evolved electric power use patterns which display considerable variability with time of day, day of the week and season of the year. As noted earlier, the loads seen by electric utilities are composites of a large number of customers, each using electricity for a variety of purposes--e.g., heating, cooling, lighting and industrial processes. The loads vary as a function of the time of the day, the relative price of electricity, the weather and economic conditions. Figure 3.1 shows a typical daily load curve for a large summer-peaking utility displaying the contribution of various classes of customers; Figure 3.2 shows a typical weekly load curve.²

One common measure of the variability in electrical demand is the ratio of average power to peak power deliveries, known as the *load factor*. In Canada, annual load factors are of the order of 60 to 80 percent. As shown in Table 3.1, the average annual load factor for Canadian utilities has exhibited considerable variability across provinces and over time. Most electric power systems were designed with the expectation of some daily, weekly and seasonal variability in electric load. While a modest level of variability is desirable, as it allows for scheduled plant maintenance, electric power is most efficiently produced if fluctuations in total system load are kept as small as possible, that is, if load factors are kept high.

Electric utilities cope with load variability in two distinct but interrelated ways. On the supply side, planners optimize system expansion by constructing a mix of electrical generating plant--base load, intermediate and peaking units--that will meet their customers cyclical demands yet minimize the total costs of providing service at a specified level of reliability. On the demand side, utilities use a number of techniques such as price, advertising or direct load controls to manage the level and timing of load. The prime purpose of managing load is to shift some of the peak demand so that the utility can more fully utilize its less costly generating capacity or reduce the need for new generating capacity. This can be achieved either by direct utility control or indirectly by influencing the customer to take the necessary action.³

FIGURE 3.1

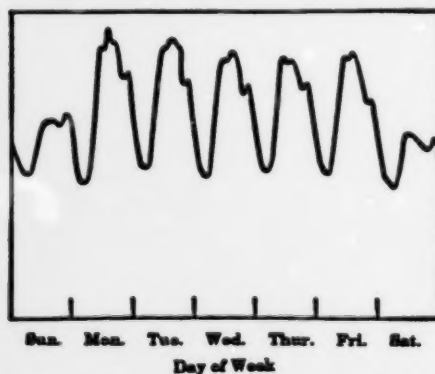
TYPICAL SUMMER DAILY LOAD CURVE



SOURCE: Sarosh Talukdar and Clark W. Gellings, eds., Load Management (New York, N.Y.: IEEE Press, 1987), p. 3.

FIGURE 3.2

TYPICAL WEEKLY LOAD CURVE



SOURCE: Sarosh Talukdar and Clark W. Gellings, ed., Load Management (New York, New York: IEEE Press, 1987), p. 4.

TABLE 3.1
LOAD FACTOR BY PROVINCE
(percent)

Province	1960	1965	1970	1975	1980	1985	1987	1988
Nfld.	66.5	72.6	71.4	68.7	65.3	64.5	66.1	68.4
P.E.I.	66.4	65.4	65.8	65.4	68.4	64.9	70.3	63.3
N.S.	59.5	66.4	62.7	58.4	59.3	62.0	61.6	59.6
N.B.	58.0	60.3	60.0	62.2	53.8	62.5	59.7	57.2
Que.	85.6	72.5	71.5	67.9	65.3	64.5	62.6	65.0
Ont.	66.4	65.4	65.8	65.4	68.4	64.9	64.2	67.4
Man.	59.5	66.4	62.7	58.4	59.3	62.0	54.9	56.0
Sask.	58.0	60.3	60.0	62.2	53.8	62.5	64.6	67.4
Alta.	55.5	57.1	59.6	64.2	68.2	72.3	78.4	77.1
B.C.	72.1	71.6	65.5	64.4	66.2	66.1	66.4	76.6
Yukon	53.5	77.8	64.4	60.9	58.0	54.3	72.5	66.8
N.W.T.	76.1	58.6	85.8	71.3	69.6	70.6	48.0	47.9
Canada	72.3	68.1	66.8	65.7	65.6	65.1	64.3	67.2

SOURCE: Energy, Mines and Resources Canada, Electric Power In Canada, 1988 (Ottawa: Minister of Supply and Services, 1989), p. 22.

Demand-side management refers to the planning and implementation of utility activities designed to influence electricity use in ways that will produce desired changes in the pattern and magnitude of the utility's load. The utility benefits through changes in the time patterns and magnitude of electricity use, thereby maximizing the use of resources. The customer benefits in being better able to utilize energy and control energy costs, thereby forestalling increases in rates that would otherwise be necessary.

DSM includes only those activities that involve a deliberate intervention by the utility in the marketplace to alter its load shape. Under this definition, for example, naturally occurring conservation, such as customer purchases of energy efficient refrigerators as a reaction to higher energy prices, would not be classified as demand-side management. However, a utility initiated incentive or advertising program that encourages customers to install energy efficient refrigerators meets the definition of demand-side management.⁴

DSM programs are undertaken to control load growth, alter the shape of the load curve or increase the supply through non-utility sources. These actions may be initiated to reduce capital expenditures, improve capacity limitations, reduce the cost of service, improve system efficiency or improve system reliability.

DSM actions may be normal procedures or emergency procedures. The normal procedures include: indirect actions or control (e.g., conservation, incentives and customer installed energy management systems); non-utility sources of supply; direct utility control of customer equipment (e.g., demand limiters and utility installed energy management systems); customer awareness; rate design (e.g., time-of-use pricing, peak rates and interruptible rates); and the installation of energy storage. The emergency procedures include energy curtailments (voluntary or mandatory) and voltage reductions.⁵

DSM was practised as early as the 1890s to promote daytime uses of electricity—electricity at the time was primarily used for lighting—but only started in a major way in the 1960s and 1970s. These early programs were directed to two areas: one to build off-peak and winter load by encouraging programs involving storage space heating, and the other to clip peaks through control of electric water heaters. Today, DSM is a subject of ongoing interest in regulatory circles, and for the public at large. For example, in the United States

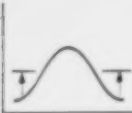
about 300 utilities run some 1000 separate projects aimed at shaping future demand.⁶

Figure 3.3 and Table 3.2 show the six basic types of load-shape changes and examples of program options most likely to succeed for each of the major customer classes--residential, commercial and industrial. The first three types of changes depicted in Figure 3.3 and Table 3.2 are classic load management techniques; the latter three are newer and considered part of the DSM umbrella.

- Peak clipping, or the reduction of the system peak loads, is one of the classic forms of load management. Peak clipping is generally considered as the reduction of peak load by using direct load control. Direct load control manipulates the appliance load by de-energizing the appliance and restricting its use in a predetermined duty pattern. Utilities most often use direct control to reduce peak demand and thereby the need to build or purchase the capacity to meet it.⁷
- Valley filling refers to building loads in off-peak periods which act to reduce the average cost of electricity to all customers by improving system load factors.
- Load shifting involves shifting peak loads to off-peak time periods without necessarily changing overall consumption. Popular applications include use of storage water heating, storage space heating, cool storage and customer load shifts.
- Strategic conservation affects end-use consumption so that overall electricity sales are reduced by altering specific patterns of use. Appliance efficiency improvements and insulation programs are examples of strategic conservation.
- Strategic load growth produces a general increase in sales beyond any increase from valley filling. This is accomplished by increasing the market share of loads that are, or can be, served by other fuels, as well as general economic development.
- Flexible load shape means that the utility is allowed to adjust the load shape to meet its reliability constraints. This is done by offering customers price incentives in return for reduced levels of service. The most common reduced levels of service are: interruptible or curtailable service, and imposition of devices that limit the power and energy that individual customers can draw.

FIGURE 3.3

LOAD-SHAPE AND DEMAND-SIDE ALTERNATIVES

Objective	Example Programs
Peak Clipping	 Load Shedding Direct Load Control Time-of-Use Rates Interruptible Rates
Valley Filling	 Thermal Energy Storage Seasonal Rates Off-Peak Rates Time-of-Use Rates
Load Shifting	 Thermal Energy Storage Time-of-Use Rates Appliance Control/Cycling
Strategic Conservation	 Audits Low-Interest Loans End-Use Solar Efficient Energy Use Conservation Rates Cogeneration
Strategic Load Growth	 Heat Pumps Dual-Fuel Heating Promotional Rates Industrial Electrotechnologies
Flexible Load Shape	 Demand Subscription Service Variable Reliability Pricing

SOURCE: Electric Power Research Institute, *Impact of Demand-Side Management On Future Customer Electricity Demand*, Project 2381-4 (Palo Alto, California: October, 1986), p. 1-4.

TABLE 3.2
LOAD-SHAPE AND DEMAND-SIDE ALTERNATIVES

Utility Load Shape	Example of Customer Residential	Options Commercial	Industrial
Peak Clipping ^a	Accept direct control of air conditioners	Accept direct control of water heaters	Subscribe to interruptible rate
Valley Filling ^b	Use off-peak water heating	Store hot water to augment space heating	Add nighttime operations
Load Shifting ^c	Subscribe to time-of-use rate	Install cool-storage equipment	Shift operations from daytime to nighttime
Strategic Conservation ^d	Supplement home insulation	Reduce lighting use	Install more efficient processes
Strategic Load Growth ^e	Switch from gas to electric water heating	Install heat pumps	Convert from gas to electric process
Flexible Load Shape ^f	Demand subscription service	Group load cooperatives	Interruptible rates

SOURCE: Sarosh Talukdar and Clark W. Gellings, eds., *Load Management*. (New York: IEEE Press, 1987), p. 7.

^aReduction of load during peak periods is generally achieved by directly controlling customers' appliances. This direct control can be used to reduce capacity requirements, operating costs and dependence on critical fuels.

^bBuilding load during off-peak periods is particularly desirable when the long-run incremental cost is less than the average price of electricity. Adding properly priced off-peak load under those circumstances can decrease the average price.

^cAccomplishes many of the goals of both peak clipping and valley filling, involves shifting load from on-peak to off-peak periods, allowing the most efficient use of capacity.

^dA reduction in sales, often including a change in the pattern of use. The utility planner must consider what conservation actions would occur naturally and then evaluate the cost-effectiveness of utility programs intended to accelerate or stimulate conservation actions.

^eA targeted increase in sales which may involve increased market share of loads that are or can be served by competing fuels, as well as development of new markets. In the future, load growth will include greater electrification—electric vehicles, automation and industrial process heating.

^fAllowing customers to purchase some power at lower than normal reliability. The customer's load-shape will be flexible, depending on the real-time reliability conditions.

3.3 DSM Implementation

There are many possible DSM program variations because most utilities design programs to meet their own specific needs. This results in a number of programs which fall into the general classification but have unique features.

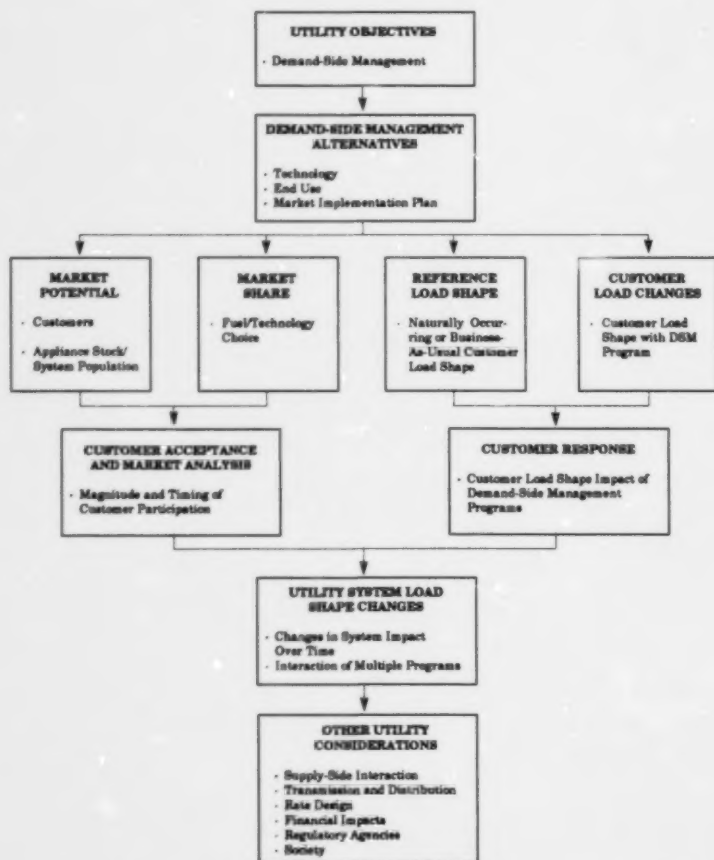
The cycling strategy (amount of time off or on, at what load levels it is implemented, and for what objectives) is very dependent on local environmental conditions, building practices, the needs of the customer and the needs of each utility. Communication can be by one- or two-way radio, one- or two-way power line carrier, microwave, telephone carrier or cable channel. It may also be controlled locally by temperature-sensitive devices or demand-limiting devices, without the need for any communication channel to the utility. The cycling control may be part of an integrated control of various appliances in the home.⁸

Utility implementation of DSM programs are typically categorized under four generic headings:

- **Alternative Pricing:** Provides customers with pricing that reflects the real cost of producing power and encourages customers to alter use patterns. In response, customers may use appliances or processes differently or they may buy new or different devices.⁹
- **Direct Incentives:** Provides customers with cash payments, rebates or credits that stimulate investment in appliances or activities that would otherwise not be economically attractive. Direct incentives are also used to compensate customers who participate in programs which offer a lower level of service, such as direct control programs.
- **Direct Customer Contact:** Face-to-face communication by utility representatives encourages customer acceptance of, and response to, utility programs. This is accomplished through on-site visits, energy service audits and workshop/energy clinics.
- **Advertising:** Increases public awareness of new programs and can influence the customer's response to the utility's programs.

The basic considerations and steps involved in the planning, implementation and monitoring of a generic DSM program are shown in Figure 3.4.

Figure 3.4
Basic Elements for Consideration
in the DSM Program



SOURCES: Electric Power Research Institute, *Demand-Side Management, Volume 2: Evaluation of Alternatives*, EA/EM-3597, prepared by Battelle-Columbus Division and Synergic Resources Corporation for Edison Electricity Institute and the Electric Power Research Institute (Palo Alto, California: December 1984), p. 13.

3.4 DSM Benefits and Costs

Analyzing the cost-effectiveness of DSM is a complex undertaking. Many variables that affect the benefits of DSM actions are uncertain--growth rates, costs, and the saturation rates and capabilities of future technology. DSM also affects the number and duration of outages, the benefits of service, and customer investments in such goods as storage devices, insulation or timers. Compounding the difficulty in the comparison with conventional supply-side options, DSM programs often reduce supply-side costs by rescheduling proposed capacity additions, or by changing the manner in which generation plants are operated.

In evaluating DSM programs, the critical issue is whether there are potential net benefits from changing the way the electric utility influences customers' decisions, either by changing electricity prices or by installing direct controls on customers' loads. The potential gains can include the reduced use of the utility's capital, labour and fossil fuel resources, as well as other benefits such as less air pollution.

Four factors make load management decisions difficult. First, when all the possible combinations are considered, a large number of choices are possible.¹⁰ DSM alternatives encompass a wide range of options in terms of technology, the end-uses to which the technology can be applied, and the methods by which the technology is marketed to customers. Evaluating the alternatives requires substantial amounts of information, which can be costly to obtain, and a strategy of quickly identifying the most attractive alternatives. These considerations have led some analysts to conclude that the utility is not necessarily the most appropriate vehicle for assessing alternatives.

Second, complex interactions among customers, the utility and regulators ultimately determine the effects of DSM programs. Since most of the programs are voluntary, participation in the program must provide adequate benefits to each group of participants. This complexity makes it difficult for analysts to project the effects of DSM programs over time.

Third, the objectives of DSM are diverse and sometimes conflicting. The analysis of an appropriate program must go beyond cost minimization to consider other effects, such as changes in the value of service to customers, inconveniences due to appliance interruptions,

reduction in the use of strategic fuels such as oil and gas and financial impacts on the electric utility.

Finally, DSM decisions must be determined in an uncertain environment. Future load growth, load patterns, technological change, fuel prices and customer responses cannot be known with certainty. The impacts of time-of-day rates and direct load controls vary by customer class and region. These uncertainties necessitate the monitoring of DSM programs to assure their continued cost-effectiveness, which in turn adds to the cost of the program. An additional consideration is that the system load shape is dynamic and will change over time. The load shape impacts of DSM programs can also be expected to change over time, which again adds to the complexity of evaluating these programs. Limitations in data and in load management assessment methodologies add to these uncertainties and the complexity of cost/benefit evaluations of DSM programs.

3.4.1 Benefits

For utilities with load growth in excess of capacity resources, DSM can provide an effective means of reducing or postponing construction of new generating facilities. Changes in the utility's system load shape may also allow adjustments in plant loadings and result in reduced costs through the use of more efficient plants.

DSM programs also increase a utility's knowledge of, and responsiveness to, its customers. To be effective, all types of DSM programs require an in-depth understanding of customer attitudes and behaviour. Monitoring the effectiveness of programs and evaluating public acceptance and utility/customer savings tends to keep customers and utilities in close contact. Many utilities view this to be a plus, even if the other DSM benefits are not significant.

DSM will also avoid some transmission and distribution costs.

Pacific Gas and Electric Company estimates that in the long-run, a kilowatt of demand management will avoid 92 percent of transmission costs associated with a kilowatt of demand and 51 percent of demand distribution costs on a long-run basis by reducing the system demand which causes the installation of these facilities. Demand management will also avoid not only the kilowatts saved but most or all of the utility's reserve margin applied to those kilowatts because the responses of customers can be statistically predicted. It

thus is likely to reduce generation needs by 1.2 to 1.25 kilowatts for every kilowatt conserved.¹¹

In addition DSM may enhance planning flexibility, for once a program infrastructure is in place DSM programs subject to regulatory purview, and staff training can be scaled up or down as required. DSM programs can also help to reduce the uncertainties associated with load forecasting.

For example, if the average new electrically heated residential customer uses 15 000 kilowatt-hours per year, a misforecast of the number of customers will have a greater affect on the load forecast than if that same customer used 8000 kilowatts per hour per year after conservation. As DSM programs are implemented, the variance in the load forecast should be reduced.¹²

From a utility's perspective, DSM program benefits include:

- reducing the need for critical fuels;
- reducing or postponing capital investment in construction programs;
- holding the line on electricity costs;
- increasing revenues;
- providing customers with options that offer a measure of control over their electric bills;
- reducing risks by investing in diverse alternatives;
- increasing operating flexibility and system reliability;
- minimizing potential environmental impacts; and
- enhancing the partnership between the utility and its customers.¹³

3.4.2 Costs

Demand-side management is not, however, without some problems and costs. Control and metering equipment can be expensive. There are also practical limits to system load factor improvement as utilities schedule much of the maintenance for their generating equipment for low-load periods. Consequently, large increases in load factor could result in higher fuel costs, as higher cost generation might be needed for longer periods of time. In addition, a

kilowatt of load reduction on specific electrical devices may result in substantially less than a kilowatt of demand reduction at time of utility system peak, due to load diversity.

In estimating class or system load shape changes, two important issues must be addressed--estimation of changes in the load shape impact over the planning horizon, and the interaction of multiple DSM programs. Impacts of load shape changes must be translated into costs and benefits and compared to other alternatives, including supply-side alternatives, as the attractiveness of DSM alternatives depends upon the existing and planned supply system and on the characteristics of the DSM alternatives themselves. This total planning context is fundamental, as DSM alternatives alter the system load shape and thereby affect the operating efficiency of the existing generation mix and future capacity additions.¹⁴

Assessing the attractiveness of a specific DSM strategy is a complex task because of data limitations, particularly the lack of information about customer responsiveness to DSM initiatives. The choice of the appropriate implementation strategies requires that the utility have sufficient understanding of a number of customer characteristics, including demographics, physical characteristics, fuel use patterns, end-use load shapes and customer attitudes toward utility programs. Obtaining this information can be a costly undertaking.

In addition, numerous factors outside the DSM program affect the load shape, and compound the difficulty of determining program costs and benefits. For example, weather conditions, economic activity, major equipment changes and changes in utilization can have significant impacts on the load shape.

From a utility's perspective, DSM program costs include:¹⁵

- initial outlay for utility control equipment;
- increased customer and utility operating/maintenance costs for end-use equipment;
- direct incentive payments to customers;
- promotional costs to gain customer awareness and acceptance; and
- costs to meet regulatory or institutional requirements.

3.5 Demand-Side Management in the United States

Although the history of DSM is long, it was not until the electricity price increases of the 1970s that U.S. utilities seriously began to view DSM as a strategic planning option (see Volume II, Appendix D for historical detail). In the United States, electric utility use of demand-side management is considerably more widespread than in Canada, and is growing.

A survey of 123 utilities completed in 1987 found that 85 percent of these U.S. utilities had implemented DSM programs. Some of these programs are over 10 years old and have already cut peak demand by hundreds and in some cases thousands of megawatts. The survey found that 76 utilities reporting funding levels spent about \$582 million on conservation programs and \$135 million on load management efforts in 1985.¹⁶

It is becoming increasingly common for U.S. utilities to offer financial incentives to stimulate efficiency improvements. Rebates and subsidized loans are the primary incentives and efficient air conditioners and heat pumps are the most common products for which these incentives are offered. In addition, some residential programs include efficient refrigerators, freezers, water heaters and lighting products. While rebates for residential equipment are more common than rebates in other sectors, commercial and industrial programs are also gaining in popularity due to the large amount of electricity used in these sectors.

A 1986/1987 survey conducted by the American Council for An Energy-Efficient Economy and the Consumer Energy Council of America (ACEEE survey) showed that utilities are typically paying \$200-300 per kilowatt for avoided peak demand, roughly one-tenth to one-half the cost of new generating capacity. Some utilities are also providing low- or no-interest loans to encourage customers to purchase energy-efficient equipment or to weatherize their buildings.^{17,18}

In addition to financial incentives, some U.S. utilities are also using competitive bidding procedures to promote electricity savings. "Demand-side bidding" involves a utility requesting that owners of buildings or outside companies propose electricity conservation projects. The utility allows the project sponsor to propose payment rates in a competitive process. Proposals are then assessed by the electric utility on the basis of cost, technical soundness and reliability. The utility then enters into contracts with winning demand-side

bidders; efficiency measures are installed and the project sponsor is paid according to the contract rate for verified savings resulting from the program.

Bidding is rapidly becoming a widespread method for securing new resources for the electric utility business. Over 15 utilities currently (December, 1988) use bidding to determine the source and price of at least portions of new supply, while several other utilities also utilize bidding methods to solicit demand-side management (DSM) resources. Some bidding programs have been initiated by state commissions, while others have been led by utilities. Although great uncertainty surrounds the prognosis for the long-term effectiveness of securing resources through bidding, many have suggested that this new method will greatly impact the industry's near-term resource mix.¹⁹

The emergence of Least-Cost Utility Planning (LCUP) over the last decade holds significant potential for expanded utility investment in end-use efficiency and load management technologies. The LCUP objective is to provide services such as heat, light and motive power—not energy per se—at the lowest possible cost. All feasible "demand-side" options are evaluated together with new energy supply options and are ranked according to their cost effectiveness. Reliability, safety, environmental impacts and social concerns are also included as criteria for resource evaluation. In the U.S., utility regulators encourage and sometimes require electric utilities to invest in efficiency and load management measures which save energy at less cost than supply-side options.

LCUP was first adopted in 1980 for the Pacific Northwest region of the U.S. The Northwest Power Planning Council was established in part to develop least-cost plans for the region. If population and economic activity in the region grow rapidly, the most recent plan calls for cutting electricity use 14 percent by 2006 at an average cost of 2.4 cents per kilowatt-hour. More recently, at least 16 states have adopted least-cost planning policies and requirements.²⁰

Minimum efficiency standards are also becoming more popular. A number of states—California, New York, Maine and Florida—have enacted minimum efficiency standards for residential appliances and in 1987, national appliance standards were adopted as U.S. law. These standards are projected to reduce peak demand in the year 2000 by some 22 000 megawatts. By effecting all products produced or sold, minimum efficiency standards can greatly promote

end-use efficiency. Appliance standards are considered the most effective conservation program in California, where they have resulted in an estimated cumulative reduction in peak demand of about 1750 megawatts by 1987.²¹ Minimum efficiency standards can complement and support utility DSM efforts in a number of ways. First, the standards have an effect on all products at no cost to the utility. This reduces the uncertainty regarding future levels of equipment efficiency, helping planners to better predict future electricity demand. Second, there are no problems with "free riders" or non-participants. Third, standards eliminate inefficient products from the marketplace.²²

The U.S. efficiency standards do not apply to exports but it is probable that products exported to Canada will embody these efficiencies, as U.S. manufacturers are not likely to run separate production lines for Canada's comparatively small market. This action would be assured if national standards were brought in to limit Canada becoming a dumping ground for inventories of low-efficiency U.S. appliances.

In 1986, the U.S. Electric Power Research Institute (EPRI) published its analysis of the potential for DSM in the United States. EPRI's conclusions are indicative of the potential for efficiency improvements in the United States and, to some degree, for Canada.²³

- While the exact magnitude is uncertain, best estimates are that DSM will reduce U.S. nationwide peak demand in the year 2000 by more than 6 percent and energy requirements by almost 9 percent;
- Strategic conservation will be responsible for most on-peak load reduction (69 percent) and all off-peak load reduction. Strategic load growth is expected to account for all on-peak load increases and for 50 percent of off-peak increases; and
- Peak clipping will reduce on-peak load by 19 percent and valley filling will increase off-peak load by about 30 percent.

The EPRI study concluded that future impacts of DSM would be significant. In total, DSM is expected to reduce U.S. peak demand in the year 2000 by 45 gigawatts, compared to what it otherwise would have been. Allowing for uncertainties--e.g., future electricity prices, success in developing DSM technologies, political and regulatory acceptance of time-of-use and interruptible rates--peak load

reduction could be as low as 20 gigawatts or as high as 170 gigawatts.²⁴

3.6 Demand-Side Management in Canada

As noted earlier, demand-side management is, for the most part, in its formative stages within Canada. Generally, interest in DSM within Canada has been less than in the U.S. owing to the comparatively low cost of Canadian power and fewer difficulties in siting and construction of new Canadian generating stations. Most of the interest in DSM in Canada stems from the utilities' interest in reducing demand and thereby deferring the requirement for new generation projects. Utilities have also come to recognize that DSM programs enhance planning flexibility as these programs can be slowed or sped up as the need arises.

The principal thrust of DSM programs in the commercial sector involves energy-efficient lighting, whereas, programs in the industrial sector are geared to promoting the use of high-efficiency motors and adjustable speed drives. In the residential sector, various rebate/information programs are in place or under development to reduce electrical consumption in the space heating, domestic hot water, appliance and lighting areas. While a number of provincial governments and electric utilities support various energy-efficiency programs, many utilities do not have active DSM programs in place. Most Canadian utilities are, however, in various stages of examining the potential of DSM programs to their utility planning.

In May, 1989 a joint study undertaken by the Canadian Electrical Association (CEA) and Energy, Mines and Resources Canada (EMR) was released on demand-side management in Canada.²⁵ That report gives a comprehensive overview of conservation, DSM and independent power programs supported by Canada's electric utilities and the various provincial and territorial governments. For an in-depth understanding of the regional status of demand-side management, readers are referred to this CEA/EMR study. The information presented below highlights some of the program information presented in that report for British Columbia and Ontario--regions which have programs in place and which are actively exploring the further potential of demand-side management.

3.6.1 British Columbia

B.C. Hydro currently has a total of 24 DSM initiatives at the conceptual, developmental or implementation stage.²⁶ Over the next 20 years, B.C. Hydro intends to invest more than \$225 million to reduce consumption by some 35 TW.h. Annual savings are expected to total 1000 GW.h in the early 1990s and grow to 2500 GW.h annually in the 2005 period. Figure 3.5 outlines B.C. Hydro's cumulative 20-year forecast for demand-side management by sector.

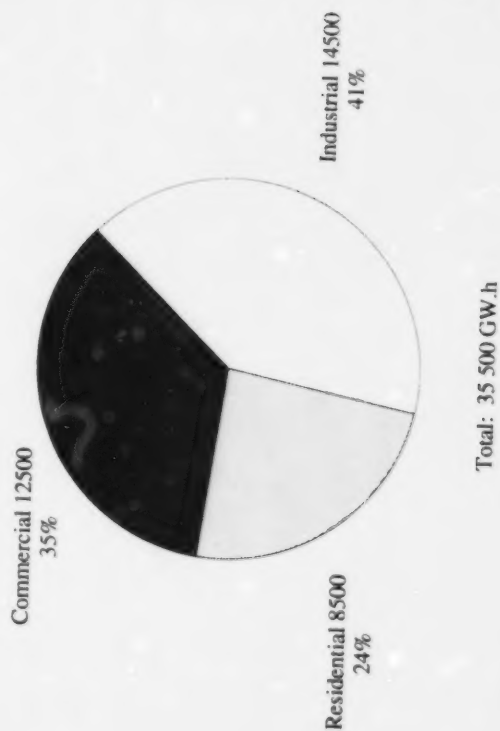
B.C. Hydro has devised several rebate/information programs to reduce electrical consumption in the space heating, domestic hot water, appliance and lighting areas in both new and existing dwellings. In the commercial sector, strategic conservation techniques are used under several programs to reduce electric consumption. The programs are characterized by extensive information initiatives supported by financial incentives. The principal thrust of the commercial programs involves energy-efficient lighting. The electrical energy savings forecast for the program are displayed in Figure 3.6.

In the industrial sector, B.C. Hydro has devised a number of programs associated with electrical motors, industrial lighting, compressors and industrial buildings. The programs are intended for both new and existing industrial installations and utilize a mixture of information and rebates. For example, the "High Efficiency Motor Rebate Program" is designed to reduce electrical energy use through rebates and education by promoting the use of high-efficiency motors in all new installations and for the replacement of failed motors. B.C. Hydro also plans to offer economic and engineering assistance in connecting existing control systems to adjustable speed drives as these motors can significantly reduce electricity use during periods when maximum output is not required (see Figure 3.7).

3.6.2 Ontario

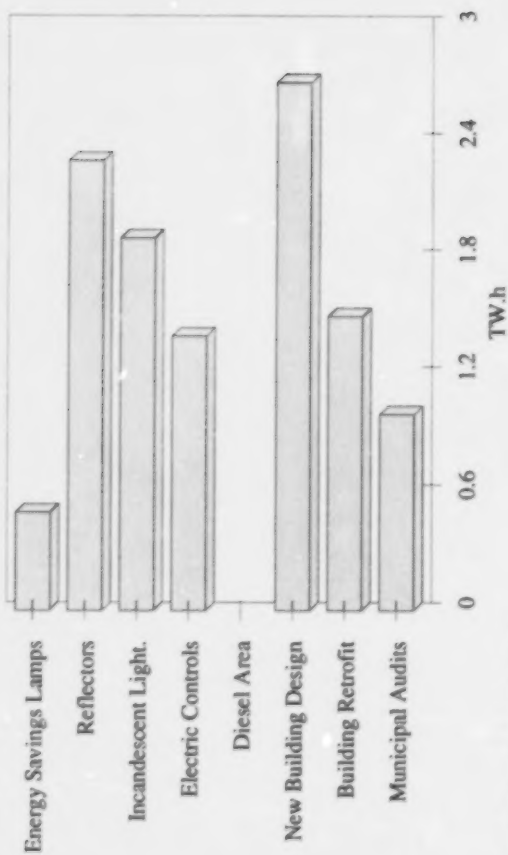
Ontario Hydro is in the conceptual/planning phase of an extensive DSM program which is expected to save upwards of 4500 MW by the year 2000. The target is for incentive-driven efficiency improvements of 2000 MW, 1500 MW of information-driven efficiency improvements and 1000 MW of load shifting, aided by time-of-use rates which went into effect last year. Information programs are to be introduced in 1989, incentive-driven programs in the early 1990s, and broad-scale implementation would start in 1993. Programs would be monitored and adjusted to market conditions and utility requirements

Figure 3.5
British Columbia: DSM Budget Goals
20-Year Cumulative (GW.h)



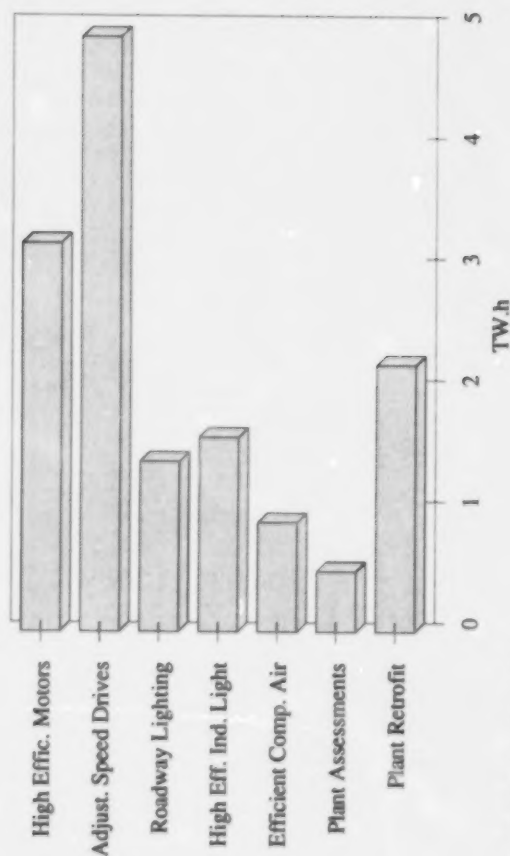
SOURCE: Canadian Electrical Association and EMR, Demand Side Management in Canada, May 1989, p. 23.

Figure 3.6
British Columbia: Commercial Sector
20-Year Cumulative Savings



SOURCE: Canadian Electrical Association and EMR, Demand Side Management in Canada, May 1989, p. 28.

Figure 3.7
British Columbia: Industrial Sector
20-Year Cumulative Savings



SOURCE: Canadian Electrical Association and EMR, Demand Side Management in Canada, May 1989, p. 31.

in the late 1990s. By the year 2000, Ontario Hydro expects that its commitment to energy management initiatives could be as high as \$2 to 3 billion.²⁷ To ensure the effective implementation of its programs, Ontario Hydro will undertake an extensive program of research and development in all sectors.

In the residential sector, Ontario Hydro expects cumulative savings of 75 MW from demand reduction by 1993, primarily from incentive-driven programs.

In the commercial sector, Ontario Hydro believes the most economic DSM options are:

- Lighting retrofits in offices, retail and hospitality buildings;
- Use of high-efficiency motors;
- Improved/more energy efficient equipment such as heat pumps;
- Use of energy management systems; and
- Load shifting technologies such as thermal storage and ice storage.²⁸

In the commercial sector, Ontario Hydro expects a cumulative reduction in demand of 483 MW by 1993, primarily from information driven and load shifting programs.

Some of the programs being initiated and/or under consideration for Ontario's commercial sector include:

- Promoting an understanding of energy management through workshops, trade shows and industry association activities;
- Providing customer services, including billing analysis, to identify opportunities for efficiency improvements;
- On-site energy audits for assessing energy usage and for recommending improvements;
- Energy management control systems in new office and public institution construction;
- Thermal cool storage to help moderate the growth in summer peak;
- Individual metering/load control water heaters; and

- Time-of-use rates for direct commercial customers.²⁹

In the industrial sector, Ontario Hydro's strategies for DSM include:

- Incentives to encourage customer installation of more efficient electrical equipment;
- Industries with high motor loads will be given a high priority in energy efficiency program development; and
- A promotional campaign will be targeted to both current and potential time-of-use customers. Efforts will focus on these industry segments that are favourable to load shifting such as cement, chemical and pulp and paper market segments.³⁰

Ontario Hydro's demand reduction target for the industrial sector by 1993 is 598 MW, primarily from information-driven and load shifting programs.

3.6.3 DSM Prescriptions

In Canada, the debate over the appropriate role of DSM has been most evident in Ontario in the past several years. Some of the recommendations issuing from this debate are indicative of the potential evolution of DSM programs in Canada.

In early 1989 the Ontario Select Committee on Energy published its report on Ontario's future electrical energy requirements. The Committee's overall recommendation was that before any commitment is made for the construction of a major new generating station, every effort should be made to: (i) maximize the capabilities of the existing generating and transmission system; (ii) identify and exploit the potential of demand management; (iii) aggressively promote private generation; and, (iv) develop the remaining available hydraulic sites in an environmentally acceptable manner.³¹

The Committee asserted that Ontario's electricity use should become as efficient as economically possible. For this to come about, it concluded that aggressive conservation programs are required *as higher electricity prices might be the only sure method of stimulating conservation* and that there is a great need for effective educational and promotional efforts related to the need for conservation.

The Committee noted that DSM programs are subject to considerable risk and uncertainty and that a workable planning

framework must consequently have substantial room for flexible response. The Committee asserted, however, that flexibility appears increasingly illusory in Ontario's electric power planning. The province has very limited indigenous oil, coal and natural gas for thermal generation, and environmental and safety concerns about nuclear power persist to the point of significantly impeding developmental actions.³² Consequently, it saw an immediate need for market research and the initiation of conservation pilot projects to reduce uncertainty about the future role for demand management within Ontario.

The Committee recommended that Ontario Hydro and the Ministry of Energy develop a complete set of realistic conservation supply functions and that these be incorporated in the planning process. It also recommended that Ontario Hydro develop a monitoring and post-audit system to determine the amounts of demand management actually achieved. It claimed that these actions would greatly reduce the current uncertainty surrounding the potential for demand management.

The Committee also noted that to achieve high penetration rates, financial assistance at levels up to the total costs of each conservation measure will probably be necessary, as long payback periods often act as a barrier to successful implementation of DSM measures.³³

With respect to conservation potential, the Committee pointed to testimony to the effect that lighting offers some of the largest potential savings, representing more than 35 percent of Ontario's total industrial and commercial electricity consumption. It urged that energy-efficiency standards for lighting be stringent and be implemented as soon as possible. It also stated its preference for compulsory rather than voluntary or price-driven measures.³⁴

3.7 Conclusions

While the increasing interest in demand-side management is relatively new, the context is fundamental to Canadian electric power planning. Least cost planning--the examination of all economic supply options at a specified level of reliability--is endemic to the regulation and development of Canada's electric power system. What has changed is that the rising cost of electricity, together with new technological developments, has broadened the number of options which need to be assessed in least-cost power planning. Unfamiliarity

with some of these new tools and their costs and benefits has caused many utilities to be conservative in adding them to the roster of supply alternatives under consideration. However, Canadian utilities are gradually recognizing that managing demand holds increasing promise as an alternative to new supply sources. Increasing concern with minimizing the impact of generation activities on the environment will sponsor greater interest in more efficient use of electric power.

While DSM appears a serious candidate to an increasing number of Canadian electric utilities, there are uncertainties associated with its ultimate potential and effective implementation. This has prompted utilities and many government bodies to stress the immediate need for such research and development initiatives as DSM pilot and post-audit demonstration programs, development of conservation supply curves, financial assistance programs, minimum efficiency standards and time-of-use rates. Research and development is imperative as uncertainty clouds the magnitude of both the benefits and the costs of DSM.

In many instances, DSM requires the development of new metering and interface technologies at substantial costs. All types of DSM programs require in-depth knowledge of customer attitudes and behaviours--a higher degree of utility-customer interaction than has ever existed in the past. While this interaction can be costly, many utilities in the United States have found closer ties with their customers to be extremely beneficial. Comparable to all exhaustible resources, there are also practical limits to which the system load factor can be improved by DSM, as equipment maintenance is often scheduled for low-load periods and Canadian load factors are already high.

While the costs of DSM appear high, the benefits may prove to be significant. Again, research and development are required in many areas to clarify these costs and benefits. Unlike many options, however, DSM has an added advantage as it enhances planning flexibility and increases supply diversity. Moreover, in these times of increasing regional concern with environment, more effective use of electricity assumes added importance. DSM programs undertaken in the United States could offer considerable insight and a more focussed understanding of the relative costs and uncertainties associated with the broad range of supply and demand options facing Canada's least-cost utility planners.

While DSM is in its formative stages, the various programs in place and under consideration attest to the serious consideration that DSM has received by some Canadian utilities. While some analysts consider utility DSM targets to be low, it seems appropriate that utilities apply a conservative figure to DSM potential until the post-audit research and development is completed and utilities have finalized their cost-benefit assessments of specific DSM programs. The more important factor is that these programs be implemented and the appropriate evaluations be undertaken to address the uncertainty surrounding the potential for demand-side management in various regions in Canada.

Footnotes

¹William U. Chandler et al., Energy Efficiency: A New Agenda (Washington, D.C.: American Council for an Energy Efficient Economy, July 1988), p. 37.

²Sarosh Talukdar and Clark W. Gellings, ed., Load Management (New York, N.Y.: IEEE Press, 1987), p. 3.

³Terry A. Ferrar, Frank Clemente, and Robert G. Uhler, Electric Energy Policy Issues (Ann Arbor, Michigan: Ann Arbor Science Publishers Inc., 1979), p. 119.

⁴Electric Power Research Institute, Demand-Side Management Volume 2, Evaluation of Alternatives, prepared by Battelle-Columbus Division and Synergic Resources Corporation for Edison Electric Institute and Electric Power Research Institute (Palo Alto, California: EPRI, December 1984), pp. 3-4.

⁵Sarosh Talukdar and Clark W. Gellings, eds., Load Management, p. 5.

⁶*Ibid.*, p. 5.

⁷Electric Power Research Institute, Demand-Side Management Volume 3: Technology Alternatives and Market Implementation Methods (Palo Alto, California: EPRI, December 1984), p. 9.

⁸Sarosh Talukdar and Clark W. Gellings, eds., Load Management, p. 7.

⁹*Ibid.*, p. 13.

¹⁰Electric Utility Rate Design, Load Management: Issues, Objectives and Options, Final Report to the National Association of Regulatory Utility Commissions (Palo Alto, California: EPRI, February 1982), pp. 45-46.

¹¹William B. Marcus, Electric Utility Planning for the 1990's: Presentation for the Ontario Select Committee on Energy (Toronto, Ontario: JBS Energy, Inc., September 1988), p. 13.

¹²*Ibid.*, p. 36.

¹³Electric Power Research Institute, Demand-Side Management Volume 2, Evaluation of Alternatives, p. 15.

¹⁴*Ibid.*, p. 15.

¹⁵*Ibid.*, p. 15.

¹⁶Howard S. Geller, U.S. Experience with Utility Demand Management, prepared for the Select Committee on Energy, Ontario

Legislative Assembly (Washington, D.C.: American Council for an Energy-Efficient Economy, September 20, 1988), p. 1.

¹⁷Ibid., p. 3.

¹⁸Ibid., p. 5. While financial incentives are becoming more widespread, studies of customer behaviour indicate that a financial incentive is only one of many factors influencing customers' investment decisions. The following are required to maximize program effectiveness:

- direct programs to those responsible for investment decisions acknowledging the barriers that inhibit investment;
- tailor program design and marketing strategy to different market segments, based on building type, ownership and organizational type, company size and degree of technical sophistication;
- directly contact decision-makers to solicit program participation;
- demonstrate other advantages of energy-efficient equipment or services such as increased comfort, productivity, flexibility, or reliability; and
- reduce the uncertainty associated with conservation investments through demonstrations and guarantees.

¹⁹Electric Power Research Institute, Bidding for Electric Resources: An Industry Review of Competitive Bid Design and Evaluation, prepared by Mark J. Matousek and William J. LeBlanc for EPRI (Palo Alto, California: EPRI, November 1988), p. E1.

²⁰Howard S. Geller, U.S. Experience with Utility Demand Management, p. 10. [See also Charles Cicchetti and William Hogan, Including Unbundled Demand Side Options in Electric Utility Bidding Programs (Cambridge, Massachusetts: John F. Kennedy School of Government, August 1988).]

²¹Ibid., p. 11.

²²Ibid., p. 12.

²³Electric Power Research Institute, Impact of Demand-Side Management on Future Customer Electricity Demand, EPRI EM-4815-SR (Palo Alto, California: EPRI, October 1986), report summary.

²⁴Ibid., p. ES-3.

²⁵Canadian Electrical Association and Energy, Mines and Resources Canada, Demand Side Management in Canada (Ottawa, Ontario: Energy, Mines and Resources Canada, May 1989), pp. 15-39.

²⁶Ibid., pp. 15-39.

²⁷Ibid., p. 67.

²⁸Ibid., p. 74.

²⁹Ibid., pp. 76-77.

³⁰Ibid., pp. 80-81.

³¹Select Committee on Energy, Report on Ontario Hydro Draft Demand/Supply Planning Strategy, Volume I, First Session, Thirty Fourth Parliament (Toronto, Ontario: Legislative Research Service, January 1989), p. 2.

³²Ibid., p. 11.

³³Ibid., p. 14.

³⁴Ibid., p. 16.



Chapter 4

NON-UTILITY GENERATION

This chapter assesses the contribution of non-utility generation to Canadian electricity supply and the incentives and barriers associated with its further development in the 1990s.

In Section 4.1, the economic rationale for electricity sector regulation is addressed, paying particular attention to the circumstances which have favoured the emergence of regulated monopolies and review of how these regulations constrain the development of non-utility generation (NUG). In Section 4.2, a discussion is presented of the existing contribution of non-utility producers to electrical generation, the future potential for development, and an overview of the power purchasing policies of major Canadian utilities is presented. Section 4.3 deals with pricing and access issues faced by non-utility generators. Section 4.4 outlines the issue of incentives and barriers (technical, economic and financial) to non-utility generation. Finally, in Section 4.5, an assessment of non-utility generation in the United States is presented and an evaluation made of the likelihood of similar results in Canada.

4.1 Economic Rationale for Electricity Regulation

Economic theory indicates that government intervention is generally warranted when marketable goods cannot be provided by the private sector in an optimal amount. An industry in which the lowest cost of production is only attainable through large-scale production is generally considered to be a "natural monopoly."

A natural monopoly exists when it would be wasteful and inefficient to have more than one supplier meeting customer needs in any particular geographic location. This occurs when the size of an efficient operation is very large in relation to the size of the market or, as is more frequently the case, when duplication of facilities would involve public inconvenience.¹

The lowest unit cost can be attained only through large-scale production in industries that exhibit diminishing long-run marginal costs with increased production output. Producers who operate on a

small scale are not in a position to exploit scale economies. They will, therefore, produce at a higher cost than a large producer who can capture the scale economies of production. Even through competition, the magnitude of the available economies of scale are such that the emergence of a single large supplier would naturally occur.

In spite of the lower costs achievable through large-scale production by monopolies, government intervention is typically required to protect consumers from higher prices which would be imposed as a natural consequence of monopolistic behaviour. Under monopoly market conditions, a product will be produced at a higher price and in a lesser quantity than that which would have been observed in a competitive market. As a result, the government will often award an exclusive market franchise to a single firm and then regulate either the price or the quantity produced, to ensure that the firm does not benefit unduly from monopoly power. Without this intervention, a *laissez-faire* policy would allow the firm to set a price significantly above marginal costs, resulting in an inefficient allocation of resources and a significant redistribution of income from consumers to the monopolist. There are, however, problems with this approach. In the past, regulatory agencies have found it difficult to determine the price and/or quantity necessary to achieve a fair return to the producer and an efficient allocation of the resource to the consumer.

For several decades, Canada's electricity sector has been considered a natural monopoly at the generation, transmission and distribution stages. In the past, regulated monopolies have provided electricity in the most cost-effective manner by capitalizing on scale economies available from operating large-scale production and transmission facilities. Between the 1950s and the 1970s, the electricity sector experienced rapid technological progress and significant economies of scale. The abundance and concentration of resources at specific sites (e.g., Quebec and B.C.) provided incentives for the emergence of large-scale capacity additions as opposed to smaller ones.

Institutional factors have also favoured a reliance on large-scale supply sources. Historically, utilities have been required to ensure that electricity demand of a franchised area is met at reasonable prices; have earned income from a regulated rate of return based on capital investment; and have been used as a major source of economic growth providing visible provincial economic benefits. The development of smaller electricity generating options was therefore limited.

To illustrate this trend towards large-scale capacity additions, Table 4.1 presents a list of Hydro-Quebec's and Ontario Hydro's generating stations over 400 MW. Approximately 85 percent and 97 percent (respectively) of these utilities' generating capacity are included in this table (as of December 1987). As the table indicates, these utilities initiated the construction of major generating complexes during the 1960s and in particular in the 1970s. In Ontario, and to a lesser extent in Quebec, the average size of generating stations increased significantly during the 1970s. Moreover, the stations built in the 1980s tended to be of the same magnitude as those of the previous decade.

Collectively, these figures seem to indicate that over the past 30 years, increases in the average size of generating plants came as a result of the utilities' ability to capitalize on the existence of economies of scale. Over time, however, the decision to meet increasing demand through the construction of ever larger generating facilities has been questioned. The costs associated with financing these projects became a major concern with the high inflation rates of the 1970s and the high interest rates experienced thereafter. Increasing fuel prices and the cost of constructing new plants have promulgated a review of the benefits of large-scale capacity additions in many parts of Canada.

It may be argued that these factors also affect the economics of building smaller units. However, an important distinction needs to be made between large utility generation stations and smaller independent power units. Since large production units developed by central utilities have correspondingly long construction lead periods, the impact of these factors on the production costs will be significantly higher. As the total interest costs during construction increase as the construction period lengthens, higher interest rates will impact significantly on the construction costs of large facilities. In some cases, central generating facilities taking 10 to 14 years to plan and construct could appropriate about 50 percent of their capital cost to interest.² In addition, long lead times do not allow quick response to fluctuations in demand growth and/or fuel prices. As a result, new large-scale facilities could be brought on stream in a period of low economic growth and lower than expected electrical demand.

In addition, with a greater reliance being placed on nuclear power, the installation of new equipment and the implementation of safety procedures have added to facility costs. Generating plant designs have had to be modified and construction lead times increased

TABLE 4.1
LIST OF MAJOR GENERATING STATIONS
(over 400 MW)^a

Hydro-Quebec				Ontario Hydro			
Stations	Type	MW	In Service Year	Stations	Type	MW	In Service Year
Boucherville	Hydro	349	1932-1948	Sir Adam Beck #1	Hydro	138	1922-1924
		876	1950-1961			165	1955-1971
		421	1961-1967			165	1964-1965
Berensia #1	Hydro	684	1956-1969	Des Juchins	Hydro	350	1950
		240	1967			50	1967
Berensia #2	Hydro	655	1959-1960	Richard L. Hearn	Steam (coal)	400	1961-1953
		160	1967			800	1959-1961
Carleton	Hydro	655	1962-1964	Sir Adam Beck #2	Hydro	1258	1954-1958
Tracy	Steam (oil)	600	1964-1966	Robert H. Saunders	Hydro	960	1958-1959
Manic #2	Hydro	1015	1965-1967	Lakeview	Steam (coal)	3400	1962-1969
Outardes #3	Hydro	756	1969	Thunder Bay	Steam (coal)	91	1963
Outardes #4	Hydro	632	1969			320	1961-1962
Manic #5	Hydro	1292	1970-1971	Lambton	Steam (coal)	2040	1969-1970
Manic #3	Hydro	1183	1975-1976	Pickering A	Nuclear	2166	1971-1973
Outardes #2	Hydro	454	1978	Nanticoke	Steam (coal)	4098	1973-1978
LG-2	Hydro	8328	1979-1981	Lennox	Steam (oil)	2200	1978-1977
Gentilly #2	Nuclear	665	1980	Bruce A	Nuclear	3280	1976-1978
LG-3	Hydro	2304	1982-1984	Pickering B	Nuclear	2160	1983-1985
LG-4	Hydro	2601	1984-1986	Bruce B	Nuclear	3555	1984-1987

SOURCE: Statistics Canada, *Electric Power Statistics*, Volume III, Catalogue No. 57-206 (Ottawa: Statistics Canada, various years), Tables 5-9.

^aSome stations may include units with less than 400 MW. For example, the Sir Adam Beck #1 includes one unit of 190 MW and two units of 145 MW, but has a total generating capacity of 428 MW.

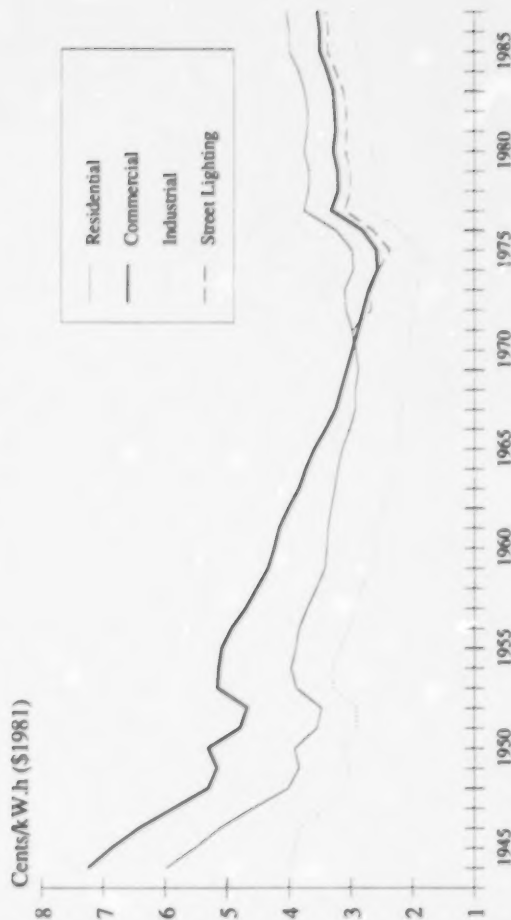
as a consequence of the increasing pressure exerted by public interest groups. Lower rates of growth in demand for electricity also reduce the attractiveness of large generating units. Together, these factors have contributed to an increase in production costs, which in turn has reduced the attractiveness of building large-scale generating plants.

Figures 4.1 and 4.2 present the historical trend of revenue per kW.h in Ontario and Quebec.³ The figures indicate that up to the mid-1970s, the cost of supplying electricity declined steadily for both utilities.⁴ An increase in production costs is observed after the mid-1970s.⁵ These costs, however, are lower than those which were experienced prior to the 1950s when the first large-scale generating plants were introduced.

These figures reflect the emergence of a new economic environment during the 1980s. Relative to the pre-1980 period, the costs of generating electricity are rising, due mainly to the systematic exploitation of the most economic hydro sites and the introduction of more restrictive environmental and safety standards (mainly for coal and nuclear). Expectations are that production costs will increase over the next decade since the most "economic" sites have already been exploited. Nuclear reactors and coal-fired stations outfitted with pollution control devices required to meet stringent safety and environmental standards, for example, are now viewed by utilities as cost-effective options. However, determining the most economic option for future capacity additions is a problem which has been compounded by the greater uncertainties faced by utility planners, particularly in the last 15 years. Large-scale projects launched in the age of uncertainty of the post-OPEC crisis, have encountered major problems as volatile fuel prices have sponsored unanticipated changes in electrical demand growth.

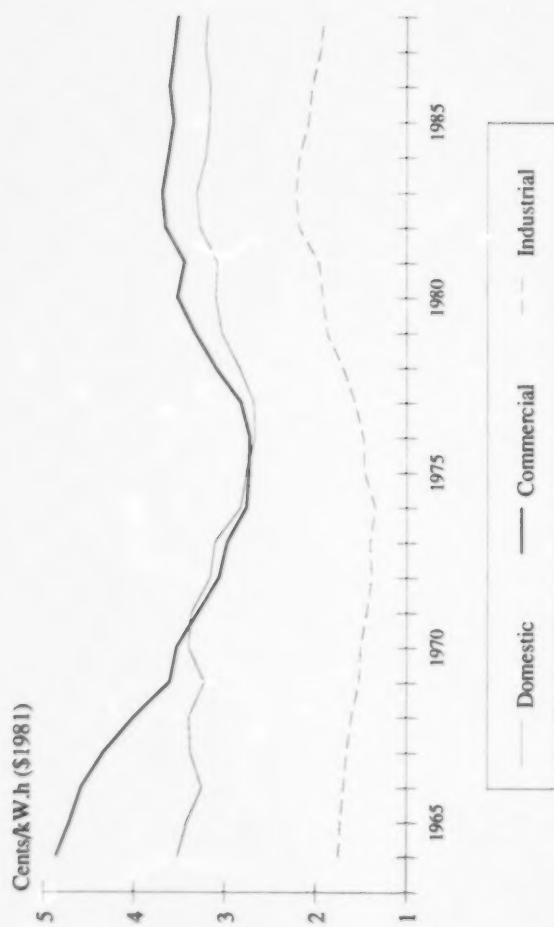
The post-1975 period, which has exhibited rising electricity prices, indicates that the benefits accruing from economies of scale have fallen. To proponents of non-utility generation, this trend provides sufficient evidence for questioning the validity of maintaining the natural monopoly argument as a justification for promoting large-scale capacity additions to meet future demand. In their view, non-utility generation⁶ constitutes, *in specific cases*, a viable electricity supply option. NUG proponents argue that most economies of scale in the electricity sector have already been exploited in the generation segment of the industry, and that natural monopoly conditions should be increasingly restricted to transmission and distribution, where economies of scale still remain.

Figure 4.1
Ontario Hydro, 1944-1987
(revenue per kW.h)



SOURCE: Report of the Hydro-Electric
Power Commission of Ontario, Ontario
Hydro, Statistical Yearbook.

Figure 4.2
Hydro-Quebec, 1964-1988
(revenue per kW.h)



SOURCE: Hydro Quebec, Annual Reports, several years.

Conversely, many contend that economies of scale still exist and that they provide sufficient economic rationale for the presence of regulated monopolies in the generation of electricity. It is not an exhaustion of scale economies that is promoting greater interest in non-utility generation, but a general increase in the cost of electricity generation coupled with electricity demand uncertainty. Up to the 1980s, NUGs were not in a position to compete with central utilities' large-scale generating stations due to low production costs. However, with large nuclear or fossil-fuelled generation stations becoming increasingly expensive to build and operate, an increasing number of industry observers contend that small NUG plants could provide competitively-priced electrical power *in some circumstances*.

NUG proponents also contend that other benefits would accrue from a greater reliance on independent power production. Since private developers generally produce electricity on a small scale, they are presumably in a better position to adapt to changes in the economic environment. The shorter lead times associated with NUG projects, for example, could minimize the impact of increases in inflation or interest rates on project costs. Moreover, some analysts assert that non-utility generation would introduce more flexibility in the long-term planning of electricity supply, be more environmentally benign, and reduce transmission costs by siting generation closer to load centers.⁷

Notwithstanding the improving attractiveness of small-scale generation, NUG cannot be viewed as a strict substitute to central utility generation. In some provinces, demand growth will be sufficient to warrant the addition of large-scale generating stations. For example, based on the 1987 peak demands of Quebec and Ontario, a 2.5 percent growth would translate the following year into additional demands of about 650 MW and 550 MW, respectively. In Quebec, annual growth could be in the order of 800 MW a year by the mid-1990s. Non-utility generation alone could not match these supply requirements.

4.2 Contribution of Non-Utility Generation

The importance of non-utility generation can be viewed from two perspectives--its existing contribution and its potential development.

4.2.1 Existing Contribution

Two problems arise in evaluation of the existing contribution of non-utility generators to Canadian electricity generation. First, it is difficult to provide a strict definition of a non-utility generator. Second, small power producers assert that their existing contribution is kept at a minimum level by the functioning of the market.

In the first instance, identification of non-utility generators is difficult. While some industrial generators might qualify as cogenerators, others would not be considered small power producers. Utilities, for example, consider Alcan and Dow Chemical facilities as load-displacement facilities rather than parallel generation facilities. For these energy-consuming firms, the self-generation of electricity is used to reduce operating costs rather than earn extra dollars from selling the by-product, even though surplus electricity is occasionally sold to municipal distribution systems or central utilities.

The divergence in estimates of the existing contribution made by NUGs to total Canadian electrical generation illustrates the difficulties encountered in attempting to identify the players who comprise this industry. Parallel generator associations, for example, estimate that there is less than 100 MW owned by small power producers in Canada, with 25.5 MW concentrated in Ontario alone.⁸ In contrast, information available for 1987 indicates that about 60 industrial establishments generated their own electricity. Concentrated in the pulp and paper, mining and aluminum smelting sectors, these producers accounted for 6.1 percent (6140 MW) of total Canadian installed capacity and generated 7.1 percent (34 230 GW.h) of total Canadian energy.⁹ These facilities are concentrated in Quebec, B.C., Ontario and Alberta. Half of the total industrial generating capacity is owned by Alcan Smelters & Chemicals Ltd. which has plants in both Quebec and B.C.

NUG's contribution may also be limited by the functioning of the market. By restricting access to their grids, utilities are in a position to limit the development of independently generated power. Moreover, small-scale producers argue that utilities' existing policies constrain private production by offering low back rates which are lower than the costs that the utilities themselves would incur to produce the same amount of electricity. The issue from the utilities viewpoint is economics. They believe that NUG pricing principles should result in prices that do not increase customer rates. The real issue from a utility's perspective is the determination of avoided costs.

4.2.2 Power Purchase Policies

The power purchase policies of electric utilities represent one of the most significant factors influencing the development of non-utility generation. Through their policies, utilities are indicating what their perspectives are on parallel generation. Some utilities are pursuing development plans without serious consideration for parallel generation, while others are opening their doors to what they regard as a reliable alternative to the construction of medium- or large-scale generating stations.

Table 4.2 provides an overview of the provincial utilities' power purchase policies. As a generalization, Canada's electric utilities are becoming increasingly supportive of non-utility generation. Two provinces in particular--Ontario and British Columbia--are actively supporting small power production. To a lesser extent, Alberta and Quebec also support non-utility generation.

As discussed in Chapter 2, Ontario could require new capacity additions by the mid- to early-1990s if electricity demand grows faster than expected. In order to meet expected demand (base or high case), Ontario Hydro is considering several options including power purchases from independent power producers (IPPs). As well, the utility is committed to encouraging renewable generation such as small hydro and wood waste, and generation based on high-efficiency cogeneration.

While some interest in NUG is emerging in other provinces, utilities have generally been reluctant to support parallel generation and currently favour project-by-project negotiations.

4.2.3 Potential for NUG

As noted above, non-utility generation could represent a viable supply alternative in certain instances. In most provinces, new generating capacity will be required by the end of the century in order to satisfy growing electricity demand and new export contracts. As discussed in Chapter 2, Canada will require some 9000 MW of new capacity by the year 2000, assuming a base case scenario which excludes capacity additions motivated by power exports. The costs and lead time associated with the construction of these new generating facilities may justify a greater role for parallel generation. If small-scale private generation is encouraged, the construction of medium or

TABLE 4.2
UTILITIES' POWER PURCHASE POLICIES

Province	Prices	Conditions	Remarks
New Brunswick	Less than 3¢/kWh	Wood-fired capacity	The previous purchase policy was based on project negotiation, with rates for some projects set at 70 percent of utility's fuel cost savings. Interest is emerging in wood-fired capacity.
Nova Scotia			The established purchase rates and policy were strongly criticized by several independent power producers as offering considerably less than the full avoided cost. A political response was introduced in 1988 for more supportive private power policy, with utility directed to select proposals for up to 30 MW capacity and to refer to the Commission of Public Utilities asked to conduct hearing to establish purchase price based on the utility's avoided cost.
Prince Edward Island	6 to 7¢/kWh		The established purchase policy for independent generation is based on utility's incremental energy (fuel) costs.
Newfoundland	Net billing (Electricity generated minus power consumed)		No official policy statement.
Quebec	From 2.8¢-3.2¢/kWh in 1985 to 3.7¢-4.2¢/kWh in 1992. Indexed to inflation.	Annual uniform rate for projects with a 75 percent capacity factor.	Rates are based on the utility's marginal costs. The rates vary depending on capacity factor, in service dates and contract duration. Estimates of potential are about 1000 MW for cogeneration and 1000 MW for small and medium-sized hydro.

(Continued on Next Page)

TABLE 4.2 (Continued)

Province	Prices	Conditions	Remarks
Quebec (con't.)	3.78¢/kW.h in winter period and 1.71¢/kW.h in summer period. Indexed to inflation.	Annual seasonal rate for projects with a 75 percent capacity factor.	
Ontario	1.71¢/kW.h	Occasional deliveries.	
	3.97¢/kW.h indexed to inflation	Projects with capacity factor higher than 65 percent and under 5 MW.	Since 1984, there is a corporate policy consistent with providing power from small producers. Additional support of low-interest loan has been introduced by utility. There is currently 470 MW of cogeneration and an additional 1000 MW could be developed if financial assistance were provided. By the year 2000, independent power developers could provide 1000 MW. It should be noted that time differentiated rates are also available.
	2.54¢/kW.h indexed to inflation	Projects with capacity factor lower than 65 percent.	
	4.94¢/kW.h	Fixed 10-year levelized rate for renewable sources. Projects under 5 MW.	
Manitoba	Negotiated prices	Projects over 5 MW.	
	Net billing	Projects under .02 MW.	Current parallel generation totals less than 20 kW. There is no direct link between cogenerators and the provincial grid.
	Negotiation	Projects over .02 MW.	
Saskatchewan	Rate to be paid are thought to be in the 1.2¢/kW.h range for base load generation and 4¢/kW.h range for peak production.		A non-utility generation policy was introduced in April 1988 with projects of less than 10 MW receiving payments for energy only based upon actual average system production costs for each year. Generators larger than 10 MW will receive payments for both capacity and energy for either peaking or base load power.
Alberta	Fixed price of 5.2¢/kW.h for contracts of 10-20 years.	For all capacity factors. Renewable fuel sources (biomass, wind, hydro). Up to 125 MW. Size limit of 2.5 MW and up to nine pilot projects over 2.5 MW.	Landmark decision in June 1984 of Alberta Energy Resources Conservation Board (ERCB) allowed power producers to bank power produced against amount purchased from utility. Rate paid for surplus production remained at 1.6¢/kW.h. February 1988 report of the ERCB and Public Utilities (Continued on Next Page)

TABLE 4.2 (Continued)

Province	Prices	Conditions	Remarks
Alberta (cont.)			
			Board recommended a policy to facilitate independent power production, focusing on small power generators with individual generating capacities less than 25 MW and a maximum initial interconnection target of 100 MW. The report first recommended that prices paid to small power producers should be based on utility long-term avoided costs, but that the only costs to be avoided until the mid-1990s would be variable fuel, operating and maintenance costs, and, second, calculated levelized prices for 1989 range from 1.8 to 2.7¢/kWh, depending on contract length. Independent power contracts might be necessary because the report production and political process is unfavourable, and political process intervened with proposed Small Power Research and Development Program, including legislation to fix purchase rate for developers of small hydro, wind and biomass projects up to 125 MW total capacity at rate of 5.2¢/kWh (reports calculated price for 20-year contract signed in 1996).
British Columbia	3.0¢/kWh in 1989, indexed to relative increases in B.C. Hydro's marginal costs. Negotiation	Projects under 5 MW and minimum contract of 20 years. Projects over 5 MW on the integrated system or any isolated projects of 20 years.	Low-interest loan and capital grants are available to projects displacing load on-site and not intending to sell power to B.C. Hydro. Performance guarantees are required. Annual capex of 25 MW is set for utilities. Small hydro projects will be selected to supply 100-200 MW through requests for proposals. Hydro will wheel IPP's power within B.C. Hydro's service and minimum contract area. A December 1988 request for proposals yielded 35 submissions for a total of 1795 MW. B.C. Hydro's Resource Plan allows for annual purchases of 1000 GW/h of NUG and 1400 GW/h of cogeneration. No official policies in place.
Yukon & N.W.T.			

SOURCE: Energy, Mines and Resources Canada, Policy Studies Group, June 1988.

large utility generating stations may be postponed and thereby reduce the need for major capital expenditures by utilities in the 1990s.¹⁰

The largest near-term potential for non-utility generation will come from industrial cogeneration projects where gas is used to generate steam and electricity. This potential will be inherently limited to provinces with an industrial structure based (partly) on enterprises which use large amounts of steam (e.g., pulp and paper, petrochemicals and petroleum refining). Accordingly, most of the potential for NUG development lies in Ontario, B.C. and Alberta. The power purchase policies of electrical utilities in these provinces indicate that small power production is viewed as a reliable alternative to the construction of medium or large central generating stations.¹¹ Alternatively, partnerships between utilities and industry may result in effective mobilization of this resource potential.

In its attempt to diversify its power sources, and meet expected and uncertain electricity demand, Ontario Hydro plans to acquire about 1000 MW of power from non-utility generation by the year 2000.¹² The utility is currently purchasing electricity from projects over 5 MW through requests for proposals and individual negotiations while standard pre-approved rate schedules apply to projects of less than 5 MW. There are four options available at pre-approved rates: a capacity-factor dependent annual escalating rate, a capacity-factor dependent 10-year fixed rate, a time-differentiated annual fixed rate and a time-differentiated 10-year fixed rate. Ontario Hydro currently receives 1098 MW from load displacement of noncontracted generators and 25.5 MW from contracted parallel generators. At this time, 252 MW of IPP projects are committed.

In December 1988, B.C. Hydro requested proposals for electricity supply to its integrated system for up to 150 MW in increments of 5 MW or larger and, in March 1989, the utility released a draft purchase policy indicating that requests for proposals totalling 25 MW (from projects less than 5 MW) will be issued annually. The utility is currently negotiating the purchase of 2500 GW.h per year from Alcan and has identified a further annual potential of 2500 GW.h from various industries. In addition, a B.C. Hydro subsidiary called POWEREX¹³ is seeking Expressions of Interest from independent power producers in supplying electricity for resale to the U.S. export market.

The Alberta government, through the Small Power Research and Development Program, has enabled NUGs operating on renewable

energy sources to sell their output to the Province's utilities at a rate of 5.2¢/kW.h (see Table 4.2). So far, under the Small Power Research and Development Program, applications have been received for some 33 projects, totalling 166 000 kilowatts. On November 9, 1989, the Alberta Transportation and Utilities Minister announced that the price paid to small producers will be increased.

... small power producers can choose between a fixed price of 5.2 cents/kilowatt hour until 1995 when it increases to 6 cents/kilowatt hour or opt for a price that starts out at 4.64 cents/kilowatt hour in 1990 and escalates with inflation.

Under both options, the utility company will pay the program price for 10 years, and in the 11th year, prices will be set by the Public Utilities Board.¹⁴

Outside the provinces noted above, utilities have not expressed a commitment to non-utility generation, indicating that the perceived benefits are generally not sufficient at this time to warrant support.

4.3 Impacts of Market Structure on NUG

The structure of the electricity market, and in particular the ability to access consumer markets, has an important bearing on the development of non-utility generation. For several decades, natural monopoly conditions have prevailed in the transmission and distribution of electricity. The regulated monopolies legally own and control the transmission networks connecting generating facilities to load centres. Since NUGs are interconnected only to the utility's grid, independently generated electricity is sold to the utility which subsequently sells it to its customers.

Non-utility generators assert that they face difficulties in accessing the market and receiving an appropriate price for their electricity as their product is not sold in a competitive market environment. In determining the price and/or the amount of electricity it will purchase, the utility is, therefore, in a position to limit the market in which NUGs evolve. Utilities argue, conversely, that NUGs prefer to compete with utilities' customer rates—and not just avoided costs. The effect is termed "bypass" and leaves other customers having to carry utility fixed costs over a smaller base.

4.3.1 Market Access

If the level at which a utility sets the maximum amount of electricity it will purchase is too low, "cost-competitive" producers may be driven out of business. In addition, by implementing restrictive interconnection standards, regulated monopolies can further constrain physical access to networks. Small power producers may not be in a position to absorb all the costs associated with the technology required to connect themselves to a utility's grid.

In order to prevent monopolistic/monopsonistic behaviour, governments typically intervene in an attempt to facilitate conditions which favour greater competition. As a consequence of limited market access, some analysts advocate a greater role for regulatory agencies.

Consideration might be given to the establishment of a new agency--a regulatory agency--to arbitrate disputes between independent producers and Ontario Hydro. ... The policy with respect to private power should be taken away from Hydro ... and made the responsibility of government.¹⁵

Not unexpectedly, this opinion is not shared by all. For example, in its testimony to the Ontario Select Committee on Energy, the Association of Major Power Consumers in Ontario stated that Ontario Hydro should have control over purchases of independent generation and be free to accept or reject any offers.¹⁶ On the other hand, it appears that exercising the right to interconnect and access distribution lines has not been problematic in Canada. As stated in the Canadian Energy Research Institute's (CERI) study on industrial cogeneration, "all of the major electrical utilities support the interconnection of customer-owned generating facilities."¹⁷ Some Canadian utilities have indicated a willingness to examine proposals regarding the wheeling of cogenerators' power between two distant plants in a local area.

Overall, it appears that the implementation of regulations intended to control physical access to networks is not a relevant consideration. In general, the provincial utilities allow the interconnection of non-utility generators' facilities. The real barrier appears to lie in the determination of an appropriate price for the purchase of independently generated power.

4.3.2 Price Determination

The price paid by regulated utilities for independently generated power determines the profitability of non-utility generation projects. Proponents argue that government intervention is needed to ensure that the correct "social" price is paid to non-utility generators.

Determining the price that will adequately reflect the "social" value of NUG power and promote its development is a complex issue. Most analysts agree that the rates offered to non-utility generators should reflect the costs the utility avoids by purchasing independently generated electricity. These "avoided costs" vary according to the location, time of delivery and reliability of the electricity offered. A debate exists over which method should be used to determine avoided costs. In general, four options are available: short-run marginal costs, the peaker approach, differential revenue requirements or the proxit unit. The four methods are defined in Table 4.3.

To accurately reflect the value of electricity supplied by non-utility generators, the use of time-of-day and time-of-season pricing has been proposed. The support for time-of-use rates, however, varies considerably across Canada. For example, Alberta's Energy Resources Conservation Board (ERCB) believes that time-of-day or time-of-season prices should not be implemented at this time. The ERCB believes it would be more appropriate to maintain simple and understandable prices during a 5-year trial period. Only at the conclusion of the trial period, when more detailed information about avoided expenditures is available, should the appropriateness of such rate structures be considered.

Interestingly, in many parts of the United States, "avoided cost" rates are being abandoned in favour of competitive bidding systems. Since utilities in the United States were forced, under PURPA legislation,¹⁸ to buy all the power offered by qualifying parallel generators, they have accumulated excess capacity which they have, in many cases, had to buy at rates higher than their actual avoided costs. In competitive bidding programs, factors such as reliability, price and amount of capacity to be purchased can be negotiated.¹⁹ However, avoided cost calculations are still relevant since they generally set the price ceiling for bidding schemes.

Adopting a competitive bidding system in Canada would be premature in most provinces as a bidding system requires that a strong and mature NUG industry with considerable project

TABLE 4.3
METHODS USED TO DETERMINE
AVOIDED COSTS

Approach	Outcome
The Short-Run Marginal Cost Approach	With this method, the avoided costs are based on fuel savings and reductions in the operation and maintenance costs over a 1-year period.
The Peak Approach	This method includes the short-run marginal costs and a capacity cost saving factor. The capacity cost saving corresponds to the reduction in the peaking capacity requirement based on a least-cost option for peaking power.
The Differential Revenue Requirements Approach	Based on energy and capacity costs, the reduction in the long-term revenue requirements derived from power purchases is estimated. In this approach, the difference in the total generation costs of a utility with and without the NUG capacity represents the avoided costs.
The "Proxit" Unit Approach	The fixed and variable costs of a potential resource (included or not in the utility's resource plan) are assumed to represent the utility's long-term avoided costs. The fixed and variable costs are defined, respectively, as the capacity and energy costs.

SOURCE: Based on H.S. Parmesano, "Avoided Cost Payments to Qualifying Facilities: Debate Goes On," in *Public Utilities Fortnightly*, September 17, 1987, pp. 34-39.

development, construction, operation and financing experience already be in place.

As power purchase rates offered by utilities are central to the financial feasibility of small power projects, parallel generators tend to favour the introduction of an independent body, such as a Public Utility Board, to determine appropriate buyback rates rather than further the development of bidding programs. In a recent survey,²⁰ firms involved or those considering involvement in Ontario's private power industry indicated that they would support the concept of public hearings to set power purchase rates and contract terms and conditions. While these firms do not generally support government intervention, they felt that Ontario Hydro's monopoly position warranted the public hearing approach.

In order for these agencies to determine the avoided costs of conventional bulk electricity generation, utilities would be asked to provide detailed information on the costs they would incur for the construction of new generation facilities.

4.4 Incentives and Barriers to Non-Utility Generation

Several other factors may affect the future development of non-utility generation.

4.4.1 Technical Incentives and Barriers

Independent of its financial viability, small power production may improve the reliability of a utility's system. The addition of smaller and more geographically dispersed parallel generating units may result in greater diversity and reliability of the grid system of a whole utility. Further, the ability to site generating units in closer proximity to load centres could reduce bulk transmission requirements and transmission losses. With regard to transmission and distribution networks, however, the appearance of a new generator may require the installation of additional equipment required to protect the NUGs' (e.g., from automatic reclosure) and the central utility's systems.²¹

Most utilities have expressed concerns regarding the availability and reliability of electricity supply from small power producers. Generation planners feel relatively confident about the resources over which they have control, but in the case of renewable energy sources such as wind, sun or water (tidal power), uninterrupted energy supply cannot be guaranteed. Utilities might have to provide standby

capacity, even during peak periods. Aside from the problems that may arise because of the unavailability of the resources used in non-utility generating facilities, utility system operators also question the reliability of NUG equipment and the skills of the maintenance personnel, asserting that standards for quality and skills are needed.

In order for a non-utility generator to connect its system to the utility's distribution network, various technical requirements must also be fulfilled and these requirements may impose major costs on a small generator.

The power distribution system owned by the utility is subject to many upsets by lightning, birds, rain, snow, ice and other whims of nature. To provide reliability and continuity to their customers, most utilities provide automatic reclosure on their main feeder breakers supplying the distribution system. The parallel generator must have suitable equipment which will disconnect the generator before the utility's automatic reclosure system is activated. A 250-kilowatt wind turbine requires about the same relay protection and controls as a huge 500,000-kilowatt generator. The protective system on a small generator can be a major cost item whereas on a large generator the cost is relatively small. ... The utilities' specifications for protective equipment may sound harsh and expensive, but in most cases there is ample justification. Utilities must be conservative and set high standards so that any failure on the generator will not upset their customers and so that upset or failure of the distribution system will not cause damage to the parallel generator.²²

In addition, proponents of cogeneration argue that industries may improve the quality of their steam and products by generating electricity (or heat) with their own cogenerating facilities. By having control over the generation of the power they consume, cogenerators are in a position to maximize the use of the steam and heat required by their production process. There is, however, a downside to this approach. First, cogeneration requires the provision of standby power which may reduce the benefits this type of small-scale production provides to the grid system. Secondly, since utilities supply backup or emergency power to cogenerators, interconnections need to be maintained and transmission losses may still occur.

4.4.2 Economic Incentives and Barriers

The emerging interest in some provinces towards non-utility generation can be explained, in part, by its economic attractiveness. In

certain circumstances, non-utility generation is cost effective and induces an efficient allocation of resources. In following more effective planning strategies, such as a combination of non-utility generation, load management and conservation, Canadian electric utilities could introduce more flexibility into their planning process and promote a more efficient use of resources.

Because of the uncertainties associated with long-term planning (e.g., demand growth, future fuel prices, etc.), non-utility generation could bring more flexibility to the planning of capacity additions by providing projects with shorter lead times, reducing required reserve margins and diversifying fuel mix. By integrating NUG into their planning processes, utilities could also more easily adjust their capacity additions in order to more closely match demand fluctuations. Because the supply increments are generally much larger than the capacity required to match demand growth, central utilities often register excess capacity when they bring a new generating station on line. A greater reliance on non-utility generation could thus exert some downward pressure on the financial burden imposed by unused capacity. However, for this argument to hold, NUGs must be willing to wait until the utility needs the capacity; otherwise, generation-in-place will exceed system requirements.

In certain circumstances, the opportunity cost associated with independently generated power could be lower than that associated with utility production. In the case of remote and off-grid generation, utilities agree that non-utility generators can produce electricity at a lower cost. Extending the grid system to remote areas implies major capital expenditures which may significantly raise the cost of providing electricity. In terms of resources devoted to the generation of electricity, it may be less expensive to produce power based on local sources than to connect these areas to the network.

Cogeneration provides a flexible option for meeting load requirements in remote regions, a source of inexpensive power in relatively high-cost utility jurisdictions, a vehicle for addressing waste management concerns, and a cost-effective option for more efficiently utilizing scarce energy resources. As a result, cogeneration should be considered as a planning resource in the same manner as utility-owned generation sources.²³

Non-utility generation projects are also generally more environmentally benign than projects based on conventional utility supply resources. Because they are dispersed, smaller and generally

more fuel efficient, they are often more manageable and more easily integrated into their surrounding environment. To some extent, NUG can reduce the stress imposed on the environment by providing an alternative to the construction of large generating stations. However, a greater geographical dispersion of environmental impacts should not be interpreted as an important benefit of non-utility generation. Local impacts can still be significant. Several small-scale hydro plants could generate local impacts on the environment that are as undesirable as the emissions created by a large-scale, coal-fired generating station.

In addition, utility planners have expressed some concerns over the long-term availability of independently generated power. In the case of cogeneration, for example, the excess power might not be available if a supplying company goes out of business in 10 or 15 years. Moreover, since fuel prices are an important factor in the profitability of a project, small power producers might be driven out of business if major fuel price increases are experienced. Utilities typically plan conservatively and require that private producers negotiate a fixed price with fuel suppliers for a period of 10 to 15 years. A number of companies are, however, too small to negotiate these long-term contracts. As a result, electricity is less valued from the utility's point of view. Other costs would also be created. Legal and administrative costs associated with negotiating, drafting and administering power purchase agreements would be a new and growing cost element. These costs may override the benefits stemming from the enhanced planning flexibility provided by NUG.

An additional consideration, often referred to as the "level playing field" argument, is generally invoked in any discussion of the barriers to non-utility generation. Private producers argue that they are at a disadvantage as Canadian utilities are chiefly government-owned crown corporations and thereby enjoy better financial terms than private sector interests through preferential interest rates and government-backed loan guarantees. In addition, as they are not subject to direct corporate taxation, utilities can produce electricity at a lower cost than private industry which must pay corporate taxes and does not have government-backed debt financing.

The comparatively low interest rates that public electric utilities are able to obtain with the protection of their government guarantee, their heavy debt burdens and their low return on equity combine to create a situation in which the capital cost incurred by electric utilities in Canada is lower than they would incur if they had to face the same conditions as the rest of the

economy, namely no guarantee on their debts and competitive rates of return on shareholders' equity. ... This has the effect of stimulating higher domestic demand, and the prices paid for electricity by consumers are marginally lower than the cost of the resources used.²⁴

Moreover, as utilities are the primary users of nuclear or coal, measures reducing the cost of these fuels is perceived as "tilting the playing field" in favour of utility-generated power. For example, subsidies granted to the nuclear industry, coal mining and uranium extraction would exert a downward pressure on the production costs of provincial electric utilities.

4.4.3 Fiscal Incentives and Barriers

Five key economic variables are likely to impact on the financial feasibility of a NUG project: capital costs, operating costs, the costs of electricity, buyback rates and tax treatment. The capital and operating costs are primarily a function of the technology used, the size of the facility, and fuel prices and availability. Private producers contemplating NUG must give special attention to the buyback rates offered by utilities. The financial viability of a project will also be influenced by fiscal incentives and the possibility of wheeling power between two different locations of a firm's plants. Factors such as capital and operating costs are fixed through market mechanisms, while buyback rates, fiscal incentives and the willingness to wheel a cogenerator's power rely on government and utility policy initiatives.

As part of the federal government's oil philosophy of the late 1970s, a special Capital Cost Allowance provision in the Corporate Income Tax Act was implemented which had the effect of promoting the use of cogeneration and small-scale electricity generation. Class 34 depreciation, which provided depreciation over the first 3 years of a plant's life (25 percent in the first year, 50 percent in the second year, and 25 percent in the third year) encouraged non-utility generation by allowing for an accelerated deduction on the purchase of certain energy conservation equipment, heat and power generating equipment and small hydroelectric generating equipment. According to Energy, Mines and Resources Canada, "between program inception in May 1976 and February 1988, 287 projects have been approved totalling \$215.2 million in eligible costs."²⁵

The Class 34 incentive was intended to encourage taxable firms to acquire energy conservation equipment in order to diversify Canada's energy sources and conserve conventional non-renewable

energy supplies. In its February 1988 budget, the federal government proposed to limit the availability of Class 34 to taxpayers who either use the energy produced directly, or corporations that sell the energy as their principal business. Even though small power producers are still eligible for the deduction, some analysts are concerned with the impact of this change.

... the restriction on Class 34 will cut off an important source of funding for conservation and renewable energy production. It is felt that while curbing potential abuses by non-taxable corporations and passive investors, the budget measure will also adversely impact on "true" investments.²⁶

4.4.4 Other Issues

Various other factors can limit the development of non-utility generation. For example, according to some cogenerators, "institutional" barriers constrain the development of parallel generation.

... the electric utilities cooperate and share among themselves available resources during peak periods and disturbances, providing in this way a very reliable and dependable electric service to their customers. There are costs associated with this cooperation and a system is in place to allocate cost or buy and sell electricity as available and required. The electric utilities have established a tradition of cooperation. But they find it difficult to extend this cooperation service to a parallel generator who may also be a customer as well as a contributor to the overall system.²⁷

Furthermore, it is rather difficult to imagine how cogeneration could fit into a strategy for market development. For a utility, the development of cogeneration facilities means a loss of base load which might result in higher electricity costs for remaining utility system customers. A larger share of the remaining customers would be served by more costly intermediate and peaking capacities. This effect should be accounted for in avoided cost calculations. In ¢/kWh, the avoided cost of base load energy is less than the avoided cost of a dispatchable source of peak energy. Over the short term, the loss of industrial load may be an important consideration for a utility's marketing department. It should be noted, however, that even if the loss of base load might constitute a barrier to the development of parallel generation, it is not considered to be of significant concern to the majority of Canadian utilities. Partnerships between the utility and cogenerator are a possible means of resolving potential conflicts.

Several points merit attention with regard to non-utility generation and protection of the environment. Although parallel generation projects are *generally* environmentally sensitive, some concerns have been expressed regarding the ability of small power producers to bypass environmental assessment review processes. For example, stream flows could be affected by small hydro developments and stack emissions from the burning of municipal solid wastes could impose additional stress on the environment.

Finally, small power producers advocate that socioeconomic benefits are derived from parallel generation. They argue that developing the parallel generation industry will generate economic activity on a local basis, reduce debt guarantees provided by provincial governments and increase the industrial tax base. The Alberta Energy Resources Conservation Board believes, however, that socioeconomic benefits associated with small power projects should not be considered in the derivation of buyback rates. These should be recognized through direct government initiatives such as taxes and grants. Electric consumers should not be expected to finance these benefits through augmented electricity rates.

4.5 Non-Utility Generation in the U.S.

During the 1970s, changing economics led the U.S. to question the manner in which their electricity sector functioned. Construction and operating costs had escalated alarmingly due to high inflation and interest rates, and growing safety and environmental requirements. Fuel costs rose significantly after the implementation of the Clean Air Act in 1970 and as a consequence of OPEC pricing policies between 1973-1974. While the price of coal was rising as a result of the implementation of more stringent safety standards in coal mines, utilities were investing large sums of money to convert their existing coal-fired units to oil and installing pollution control equipment.

Faced with the rising costs of fossil fuels, a growing dependence on imported oil and the possibility of a Middle East crude oil embargo, the United States became concerned about the security of their energy supplies. In order to reduce the country's dependence on foreign energy sources, utilities were strongly encouraged to convert (or reconvert) their generation facilities to coal. A greater reliance on nuclear power was also considered, but several factors limited expansion of this technology. Construction costs generally exceeded expectations as a result of the increase in inflation, interest rates and labour

costs. The regulatory safety standards imposed after the 1979 incident at Three Mile Island had a significant impact on the capital and operating costs of nuclear stations. Delays and cancellations of nuclear generating capacity were experienced as environmental and citizens' groups intervened in siting and licensing procedures. Environmental protection became a growing concern to many Americans, resulting in increased attention being directed to the disposal of solid waste in an environmentally and economically acceptable manner.

On the demand side, the oil shocks of the 1970s and the global economic recession of the early 1980s exacerbated the situation. As electricity rates were forced higher, demand for electricity fell leaving many utilities with unplanned, excess capacity. Within the existing regulatory framework, the utilities were not able to raise prices quickly enough to cover cost increases and thus experienced reductions in their earnings. As many utilities were also trying to finance construction programs, this reduction in earnings implied increased demands on external financing as many utilities were unable to recover costs associated with excess capacity as a result of regulatory decisions. Financial markets reacted adversely and many utilities had their bond ratings downgraded. Due to insufficient rate increases and falling electrical demand, many utilities had to cancel their plans for new capacity additions and halt construction on plants in progress.

The benefits from economies of scale and technological progress associated with large-scale generating stations appeared to have been exhausted and productivity increases slowed. The need for clean and efficient alternatives to large coal-fired generating stations provided an incentive for the promotion of new sources of energy supply. As a result, in 1978, the federal government passed a series of Acts under the umbrella of the National Energy Act (NEA), designed to create a comprehensive energy policy which would, in particular, support the development of indigenous energy sources.²⁸

4.5.1 PURPA Legislation

A component of the NEA, the Public Utility Regulatory Policies Act (PURPA), was implemented to encourage small power production and cogeneration and to provide an assured market and price structure for these power producers. Through PURPA, utilities are required to purchase all output of qualified facilities (QFs) and cogenerators at rates that do not exceed the electric utilities' avoided costs. (Table 4.4 presents PURPA's key features).²⁹

TABLE 4.4
PUBLIC UTILITY REGULATORY
POLICIES ACT OF 1978
(PURPA)

PURPA authorized the Federal Energy Regulatory Commission (FERC) to establish rules to encourage "small power production" and cogeneration by non-utility companies and to encourage the sale of electricity to utilities. The law provides an assured market and price structure for these power producers.

The FERC subsequently developed rules to implement PURPA's mandates, the key features of which were:

- **Qualifying facilities (QFs):**

The FERC established two kinds of facilities as qualified to require utilities to buy power:

- (1) "Small Power Producers" (SPPs), with capacity less than 80 megawatts, for which at least 75 percent of the energy input must come from biomass, waste burning, renewable resources, or geothermal heat, and
- (2) cogenerators, for which there is no maximum or minimum size.

- **Avoided cost:**

The concept of "avoided cost" was established as the way of determining how to price the electricity sold by SPPs and cogenerators. It was defined as: "the incremental cost to an electric utility of electric energy or capacity which, but for the purchase, the utility would generate itself or purchase from another source."

- **Limits of Ownership of QFs:**

No more than 50 percent interest in a QF could be owned by an electric utility, utility holding company or any partially-owned subsidiary of either.

SOURCE: Arthur Andersen & Co./Cambridge Energy Research Associates, Electric Power Trend (Cambridge, Mass.: Cambridge Energy Research Associates, 1989 Edition), p. 6.

In requiring utilities to purchase QF's power, the PURPA and accompanying FERC regulations provided the incentives necessary for the emergence of a new industry.

By late 1988, QFs with a combined generating capacity of as much as 10 000-15 000 MW were in operation and QFs with an additional capacity of approximately 5000 MW were under construction.³⁰

The PURPA experience has not been, however, entirely positive. Computation of avoided costs, the definition of a qualifying facility and the restrictions imposed on the ownership of such facilities have been challenged in courts. In some areas, the obligation on the utility to purchase QF power resulted in oversupply. In some cases, the economics of generating electricity changed over the term of the original contract, resulting in some utilities being required to purchase power at rates higher than their avoided costs.

While it has been in place for over 10 years, PURPA has not resolved all the difficulties which promulgated its enactment. For example, "PURPA requires a utility to purchase power from any qualifying facility, regardless of its location, but does not require a utility to wheel power on behalf of the cogenerator or its customers."³¹ In addition, granting QF status to a producer does not mean the facility will be constructed. Difficulties in meeting environmental standards or financing the project may indefinitely delay the construction of a proposed plant. Utility planners are thus still facing uncertainty with regard to the planning process and QFs can only be considered as "likely sources" of electric power. Moreover, as the availability of "economic" projects diminishes, the definition of a QF itself is perceived by many to be a *barrier* to additional non-utility generating capacity. "Cogeneration status requires a steam or waste heat use and that is becoming increasingly difficult to find. Alternative fuels are also difficult to work with and the small power size limit of 80 MW is a problem."³²

According to a study carried out by the U.S. Department of Energy,³³ PURPA's implementation has achieved some, but not all of its intended goals. An expanded range of electric generation technologies and a reduced need for investment by utilities has resulted from the increase in the number of QF-type producers. However, in some jurisdictions PURPA resulted in higher costs for customers and increased use of oil and gas. The study cited the following deficiencies:³⁴

1. setting rates greater than full avoided cost;
2. requiring utilities to pay for capacity when it does not require the capacity;
3. blurring of the lines between sunk costs and avoided costs;
4. setting rates without consideration of QF reliability and availability;
5. adopting incentive payments to encourage developments that are not based on avoided cost;
6. using state-wide uniform rates which do not take into account the variation in avoided cost among utilities;
7. mandating the purchase of QF output in instances where it forces the utility to deviate from its most efficient dispatching and operating practices; and
8. restricting utilities from competitively soliciting least-cost sources of capacity if such is not provided by the QFs.

These factors served to create an inefficient allocation of resources. The existence of QF rates which deviate from the utility's full avoided cost has favoured the generation of electricity at a cost higher than the social opportunity cost. Furthermore, the restrictions imposed by PURPA on size, fuel, efficiency and operating standards, and utility ownership have adversely affected capital markets by diverting funds to QF producers and away from developers whose investment decisions are based solely on cost and efficiency factors.

The variety of avoided cost methodologies used by individual states resulted in a regional diversity in QF rates. In addition, the regional response to state-uniform prices has varied according to resources' endowments, the size and growth of the industrial base, and the economics of individual projects. The states of California and Texas, for example, have had significant QF and cogeneration response due, to the setting of QF rates that now exceed avoided cost and the availability of a favourable industrial base.

As noted in Section 4.3.2, many U.S. utilities seem to be in the process of abandoning avoided cost-based rates in favour of competitive bidding programs. This trend is interpreted as a natural evolution in the development of non-utility generation. As a means of securing new supply options, seven states have approved competitive

bidding procedures (California, Connecticut, Maine, Massachusetts, New Jersey, New York and Virginia) and two more are developing regulations (Michigan and Vermont).³⁵ At least 20 states have either approved bidding or are actively considering whether to implement a bidding scheme.

Although competitive bidding programs have been implemented by several utilities, many questions remain. The role of utilities and the ranking of projects need to be addressed. How can we ensure that bids will be fairly evaluated when the utility (or a utility's subsidiary) is one of the bidders? Should the utility be a judge, a purchaser and/or a bidder? How should we evaluate and weight economic factors, non-economic factors, and project status and viability factors? Should a price ceiling be introduced? Further research and demonstration is ongoing to satisfactorily answer these questions.

In an effort to gather such information, an experiment comparing bidding and negotiation was held in Massachusetts. Interestingly, developers surveyed indicated that they preferred negotiations over bidding by a margin of nearly five to one.³⁶ Based on this experiment, it appears that negotiation leads to more installed capacity and provides the flexibility necessary to respond to unique project requirements. Developers indicated, however, that in order to reduce the time taken in negotiation, clear evaluation criteria and standardized contract terms are needed. The methodology used in the bidding programs also needed some refinement. The point system, for example, seemed to give too much weight to price factors. The procedures appeared to drive prices unrealistically low and favoured the selection of projects which were unfinanceable. Prequalification of bidders to screen out projects with little likelihood of success was also recommended.³⁷

4.5.2 Lessons from the U.S.

Two major factors differentiate the development of the Canadian and U.S. electric power industries. First, since hydroelectric power is very important in Canada, concerns over the security of energy supplies have not been as significant in Canada as in the United States. Second, Canadian industrial electricity generation has benefited from accommodative interconnection and standby policies for NUGs on the part of most utilities. Most of these policies were developed on a voluntary basis. Overall, non-utility generation seems to have played a different role in Canada. Canadian industrial

electricity generation was developed primarily to meet on-site power requirements of individual companies.

Unlike the U.S., the Canadian economic and regulatory environment would not have warranted the implementation of PURPA-type legislation. In Canada, the existence of large economies of scale and low production costs would have resulted in avoided costs which would have translated into purchase rates too low to permit the economic development of a large non-utility generation sector.

While different circumstances have characterized the development of small power production in the past, there is some basis for comparison between Canadian NUG and the U.S. independent power industry. Unlike the case with QFs, U.S. utilities are not required to purchase independent power producers' (IPP) electricity output at avoided cost rates. Utilities are free to negotiate the purchase of IPP output as they deem it to be required in satisfying growth in electrical demand.³⁸ Consequently, the IPP market is highly competitive.³⁹ In fact, in order to stimulate the development of an IPP industry, the FERC proposed in March 1988 rules which defined IPP, proposed competitive bidding programs and addressed avoided cost calculations.⁴⁰

For the most part, non-utility generation is a relatively new factor in Canadian electric power planning and, as a consequence, many questions remain to be answered. Utilities have expressed concerns regarding the reliability and availability of the power offered. The provision of market access and appropriate purchase rates, as well as the appropriate role for regulatory agencies, are questions requiring examination. The U.S. Federal Energy Regulatory Commission's rules and task force recommendations may provide valuable insight on how to address similar difficulties in the Canadian electricity market. It may be relevant, for example, to appraise from a Canadian perspective the rules proposed by FERC defining competitive bidding programs and addressing the calculation of avoided costs.

4.6 Conclusions

For several decades, the Canadian electricity sector has been considered a natural monopoly where regulated utilities have provided electricity in the most cost-effective manner by capitalizing on economies of scale. The abundance and concentration of resources at specific sites provided incentives for the emergence of large-scale generating plants as opposed to smaller ones. Up to the 1980s,

independent power producers were not in a position to compete with the low production costs associated with central utilities' large-scale generating stations. However, recent changes in the economics of electricity generation portend greater market opportunities for non-utility generators in the 1990s.

Increasing construction costs and planning uncertainties are sponsoring a review of the economics of large generating plants. Factors such as higher inflation and interest rates, more stringent safety and environmental standards, volatile fuel prices and unanticipated changes in electrical demand growth have exerted an upward pressure on production costs and reduced the attractiveness of large-scale generating plants. It is this general increase in the cost of electricity generation coupled with the planning uncertainties facing large-scale generating plants, as opposed to an exhaustion of economies of scale, which portends an increasing level of participation by non-utility generators in the evolution of the Canadian electricity sector.

Notwithstanding the improving economics of small-scale generation, non-utility generation should not be viewed as a strict substitute to utility generation. In certain provinces, because of the significance of the observed base load, non-utility generation alone cannot provide the increase in supply required to match projected demand growth. The purchase of power from small producers is, however, increasingly viewed by utilities as a cost-effective supply option which could be integrated into the planning process associated with meeting future demand facing regulated monopolies. More effective planning strategies, incorporating a combination of non-utility generation, demand management, interprovincial trade and conventional supply sources would introduce more flexibility into the utility planning process and promote a more efficient use of resources. Generally producing on a smaller scale, private developers are considered to be in a better position to adapt to changes in the economic environment. Consequently, greater reliance on NUG could promote flexibility in responding to changing market conditions.

The largest potential for future non-utility generation will likely come from industrial cogeneration. This potential will be inherently limited to provinces with an industrial structure based (partly) on enterprises which use large amounts of steam, e.g., pulp and paper, petrochemicals and petroleum refining. At this time four provinces are supporting small power production: Ontario, British Columbia, Alberta and Quebec.

While some interest is also emerging in other provinces, utilities have generally been unsupportive of parallel generation. Further developments are, however, expected as new capacity additions are required. As the availability of inexpensive sources of supply diminishes, these utilities may give more consideration to the purchase of power from non-utility generators. And as the industry develops and matures, project-by-project negotiations will likely be abandoned in favour of more comprehensive power purchase policies.

However, many questions remain to be addressed. Utilities have expressed concerns regarding the availability and reliability of electricity supply by small power producers. In the case of cogeneration, for example, excess power might not be available if a supply company goes out of business in 10 or 15 years. As fuel prices are an important factor in the profitability of a project, major fuel price increases may impact significantly on a small power producer's ability to remain in business. With regard to reliability, facilities operating on renewable energy sources cannot generally provide uninterrupted energy supply. Determining the price that will reflect the "social" value of non-utility generated power is also a complex issue. While most analysts agree that the buyback rates offered to non-utility generators should reflect the cost the utility is avoiding in purchasing independently generated electricity, it is not clear how these rates should be set or by whom they should be set.

The lessons learned from experiences in the U.S. constitute an important source of information for policy analyses examining the potential for non-utility generation in Canada. For more than a decade, non-utility generation has been actively supported in the United States under the auspices of the Public Utility Regulatory Policy Act of 1987 (PURPA). While not all of PURPA's impacts have been positive, the Canadian electricity sector could benefit from examining the practicality of policies similar to those initiated south of the border.

For example, it may be relevant to appraise the rules proposed by FERC for competitive bidding programs and calculation of avoided costs. The FERC task force's recent report on transmission pricing and access is also likely to provide valuable insights on how to address similar difficulties in Canada's electricity market.

Regardless of the steps taken to promote NUG, Canadian non-utility generation will not be of the same magnitude as the potential foreseen in the United States. Canadian utilities generate

electricity at a lower cost than their U.S. counterparts, and as a result the economics do not justify a major reliance on non-utility generation. Unlike the situation in the U.S., Canadian nuclear power remains a viable generating option and there is considerable hydroelectric potential remaining in Canada. From a private industry point of view, electricity rates are often too low to warrant cogeneration, currently the main form of non-utility generation in Canada.

Despite the availability of useful program information in the U.S., further Canada-specific research is needed to better understand the role that can be played by non-utility generators in planning for Canadian electricity supply in the 1990s. There is a clear need to economically quantify the amount of electricity that can be provided by parallel producers--analysts need sufficient information to construct realistic cost curves indicating how many megawatts can be supplied at different price levels. Issues such as reliability and availability of the power offered, the provision of market access and appropriate buy-back rates, as well as the role of regulatory agencies, require examination. The Ontario Government's initiative to undertake a public review of Ontario Hydro's method of determining avoided costs could be an important first step to the further development of non-utility generation in Canada. Growing concern with the environmental implications of large-scale fossil-fuelled generation will reinforce the wide and growing interest in NUG, particularly cogeneration, in Canada.

While NUG should, *where practical*, be actively supported, care must obviously be taken.

Policies to require utilities to purchase electricity from non-utility sources should be approached with caution. There is a serious risk of deterioration in system reliability and increased cost to the consumer. Utilities should be expected to undertake efficient make-or-buy decisions for all of their product and service needs. Parallel generation, meaning construction of generation by other entities for sale to the utility, should be considered in the same context and dictated through the same economic efficiency framework as other business decisions by the electric utilities.⁴¹

Footnotes

¹Marsha Gordon, Government in Business (Montreal, Quebec: C.D. Howe Institute, 1981), p. 19.

²Passmore Associates International, The Private Power Option for Canada (Ottawa: Passmore Associates International, October 1987), p. 13.

³The discontinuity occurring in the 1970s in Figure 4.1 is explained by changes in definitions. From 1944 to 1968, Ontario Hydro provides information for the following sectors: residential, commercial and industrial. From 1973 to 1987, the data are provided for the following sectors: residential, general (under 5 MW), general (over 5 MW) and street lighting. For the sake of presentation, we assumed that general (under 5 MW) and general (over 5 MW) could be associated, respectively, to the commercial and industrial sectors.

⁴This statement is based on the following assumptions: (a) that utilities' electricity rates are set at a level which allows the recovery of all operating costs and capital expenditures, and (b) that the profit margins granted to utilities have remained relatively constant over the last 20 to 30 years. Consequently, it is appropriate to consider the revenue per kW.h as a representative measure of the average cost of supplying electricity.

⁵In the case of Hydro-Quebec, the decrease in the industrial sector after 1982 does not indicate a lower cost of production. After the introduction, in 1982, of the Phase I of the James Bay complex, Hydro-Quebec registered large amounts of excess capacity which had been sold to industrial customers and neighbouring utilities at very low rates.

⁶"Non-utility generation" refers to cogeneration (mainly industrial) and small-scale generation generally based on renewable resources such as hydro, wind, sun, biomass or tidal power. Cogeneration is the simultaneous supply of thermal energy (steam) and electricity through one technological process. The steam is used in the company's production process while the electricity is used to meet part of the firm's energy requirements. In some cases surplus power could even be provided to the utility grid. In this chapter the terms "parallel generation," "private production" or "independent power production" are used synonymously.

⁷Benefits of greater reliance on non-utility generation are addressed in greater detail in Section 4.4.

⁸Conversation with Passmore Associates International.

⁹Energy, Mines and Resources Canada, Electric Power in Canada - 1987 (Ottawa: Minister of Supply and Services Canada, 1988), pp. 1, 27 and 34.

¹⁰With higher opportunity costs for utility's production, non-utility generation may appear more cost effective.

¹¹Part of the information presented in this section was abstracted from the EMR-CEA report, Demand Side Management in Canada, Ottawa, 1989.

¹²See also Government of Ontario, Ministry of Energy, Parallel Generation Policy Paper (Toronto: Ministry of Energy, July 20, 1989), pp. iii and iv, where the Government recommends that Ontario Hydro develop a solicitation process designed to achieve its target of 1000 MW of parallel generation by 1995 and an additional 1000 MW by the year 2000.

¹³POWEREX has a lead role in the negotiation and administration of export sales agreements with U.S. utilities and purchase agreements with electricity producers.

¹⁴"Power Yield Price Going Up," Calgary Sun, November 10, 1989, p. 63.

¹⁵Ontario Select Committee on Energy, Report on Ontario Hydro Draft Demand/Supply Planning Strategy, Volume II (Toronto, Ontario: Legislative Research Service, December 1988), p. 62.

¹⁶*Ibid.*, p. 63.

¹⁷A. E. Reinsch and E. F. Battle, Industrial Cogeneration in Canada: Prospects and Perspectives, Study No. 24 (Calgary: Canadian Energy Research Institute, March 1987), p. 68.

¹⁸Public Utility Regulatory Policies Act of 1978.

¹⁹Under the PURPA regime, utilities must purchase all the output offered by qualifying facilities at a price reflecting the utility's avoided costs. The PURPA legislation is discussed in Section 4.5.1 and in Volume II.

²⁰Passmore Associates International, Review of Independent Power Bidding Procedures, prepared for the Ontario Ministry of Energy (Ottawa, Ontario: Passmore Associates International, December 1988), p. 70.

²¹Arthur Andersen and Co./Cambridge Energy Research Associates, Electric Power Trend, 1989 Edition (Cambridge, Mass.: Cambridge Energy Research Associates, 1989 Edition), p. 8.

²²Dow Chemical Canada Inc. (Joseph P. Zanyk), "Barriers to the Development of Parallel Generation in Canada" in conference proceedings, Cogeneration and Parallel Electric Power Generation: The Opportunities (Toronto, Ontario: Canadian Energy Research Institute, March 30-31, 1987), pp. 347-348.

²³A. E. Reinsch and E. F. Battle, Industrial Cogeneration in Canada: Prospects and Perspectives, p. 114.

²⁴J. T. Bernard, Public Electric Utilities: Structure, Policy and Price, Departement d'economique, Universite Laval (Montreal, Quebec: December 1987), p. 16-18.

²⁵Internal paper, Eenergy, Mines and Resources Canada, May 1988.

²⁶*Ibid.*

²⁷Dow Chemical Canada Inc. (Joseph P. Zanyk), "Barriers to the Development of Parallel Generation in Canada," in conference proceedings, Cogeneration and Parallel Electric Power Generation: The Opportunities, p. 346.

²⁸U.S. regulations are reviewed in Volume II.

²⁹The PURPA legislation is discussed more fully in Volume II. See also U.S. Congress, Office of Technology Assessment, Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition, OTA-E-409 (Washington, D.C.: U.S. Government Printing Office, May 1989), pp. 47-47 and 53-58.

³⁰Arthur Anderson and Co./Cambridge Energy Research Associates, Electric Power Trend, 1989 Edition, p. 6.

³¹Anthony E. Reinsch and Ellen F. Battle, Industrial Cogeneration in Canada: Prospects and Perspectives, p. 55.

³²Robert Smock and Mona Reynolds, "New Utility Generating Plants: When, Where, and By Whom" in Power Engineering, April 1989, p. 25.

³³Lindsay Pfeffer and Associates, Inc., Emerging Policy Issues in PURPA Implementation, prepared for the U.S. Department of Energy under contract No. PEAC01-83-PE-70404, Springfield, Virginia: National Technical Information Service, U.S. Department of Commerce, March 1986, p. v.

³⁴*Ibid.*, pp. v-vi.

³⁵*Ibid.*, p. 48. See also Richard P. Rozek, "Competitive Bidding in Electricity Markets: A Survey," in the Energy Journal, vol. 10, no. 4, pp. 117-138; and U.S. Congress, Office of Technology Assessment, Electric Power Wheeling and Dealing: Technological Consideration for Increasing Competition, pp. 137-144.

³⁶J. L. Levett and S. D. Hulkower, "Bidding and Negotiating for Power from Qualifying Facilities in Massachusetts" in Public Utilities Fortnightly, March 30, 1989, pp. 19-27.

³⁷Competitive bidding programs are discussed more fully in Volume II.

³⁸The PURPA legislation does not regulate the IPP industry.

³⁹According to Arthur Andersen and Co./Cambridge Energy Research Associates, "the IPP ... business is not nearly as well developed as much recent discussion suggests. At the end of 1988, the number of IPPs actually under construction or moving toward construction across the U.S. could literally be counted on the fingers of one hand." (Arthur Andersen and Co./Cambridge Energy Research Associates, Electric Power Trend, 1989 Edition, p. 6).

⁴⁰The rules proposed by the FERC are discussed in greater detail in Volume II.

⁴¹Canadian Electrical Association, Electricity: A Canadian Advantage, submitted to the Energy Options Conference (Montreal, Quebec: Canadian Electrical Association, 1988), p. 35.

Chapter 5

ELECTRICITY TRADE

5.1 Introduction

The basis for any trading relationship is mutual benefit to both parties to the transaction. Electricity trade was fundamental to the early development of Canada's electrical power system and it will continue to affect the efficiency and evolution of Canada's electric power system in the years to come.¹

In some instances, the out-of-province purchase of electrical power permits the deferral of indigenous generating capacity. This can be extremely advantageous where electrical load is growing rapidly or where there is significant uncertainty about future levels of electrical demand. In addition to the obvious benefits of importing power at a price less than it would cost the purchaser to produce, electricity imports may therefore provide an important contribution to planning for demand uncertainty and diversity of generation. The import of electric power may, moreover, offer the shortest leadtime of the various generation options available for consideration to the electric utility.

On the exporting side, advancing construction of generation may add flexibility to power planning, as blocks of unrequired capacity can be contracted for export until indigenous demand grows to a level which supports the use of this capacity. This permits an electric utility to add the most economic increment of generating capacity to its system, generates near-term cash flow which can allow a more gradual impact on rate increases, and creates positive employment spinoffs. Manitoba, Quebec and New Brunswick are leading proponents of this prebuild strategy. Of increasing importance, inter-utility transfers of electric power can also result in a reduction in pollution. The export of Canadian electricity (primarily hydroelectric) to the United States, for example, has displaced high-sulphur oil- and coal-fired electrical generation in the United States which would otherwise have contributed to environmental problems in Eastern Canada.

This chapter opens with a general overview of trade transactions and their benefits and costs. This serves as an introduction to a discussion of the history of Canada's international and interprovincial

trade in electricity. The future prospects for greater electricity trade are then examined and some of the more significant constraints to these developments are assessed. The chapter concludes with an analytical assessment of the potential for greater trade, the potential savings which would accrue from enhanced interregional electricity exchanges and recommendations flowing from this analysis.

5.1.1 Types of Trade

Electric power/energy transactions between electric utilities vary according to the short- and long-term needs of the purchaser of power or energy, the availability of power or energy from a prospective supplier, the relative capacity of transmission interconnections between the systems, the geographical locations of the supplier and purchaser and, of course, the price of power/energy. Electricity transactions may be paid in cash at an established price or by an agreement to return equal amounts of energy during a later, mutually agreed-upon period. Where the service areas of the two parties to a transaction are not contiguous, one or more intermediate utilities may be called upon to transport or "wheel" the electricity, receiving an appropriate payment for this service.

Table 5.1 depicts the major types of power/energy transactions in Canada and the United States; Tables 5.2 and 5.3 display the major benefits and costs of trade.

5.2 Historical Overview of Electricity Trade

5.2.1 International

International electricity trade has played an important role in the development of the Canadian electricity system, dating back to the first generating stations constructed on the Canadian side of Niagara Falls. In fact, many hydroelectric developments were originally built using funds from long-term contracts with United States utilities. The first Canada-United States electricity interconnection--a 12 000 volt line--was completed in 1901.

Exports during the early period of electrical development were generally long-term firm contracts. An export contract with a United States customer, either an American utility or a major industrial electricity consumer, was essential to the construction of several early hydroelectric developments in Canada. In most of these cases, the firm that built and owned the generating plant in Canada was a subsidiary of the U.S. firm that accepted the power.

TABLE 5.1

MAJOR POWER/ENERGY TRANSACTIONS

Firm: The supplier is obligated to deliver available power (capacity) and/or energy as scheduled for an extended period.

Non-Firm: Power (capacity) and/or energy available from surplus generating resources which is interruptible on very short notice.

Short-Term: Available power (capacity) and/or energy delivered for a specified period. Separate capacity and energy charges are usually applicable.

Unit Power: Power (capacity) and/or energy available from a specific generating unit or power plant delivered for an extended period, with availability normally dependent on the performance of the designated generating unit or plant.

Seasonal Diversity Exchange: Power (capacity) and/or energy exchanged between utilities with annual peak loads in different seasons, e.g., summer versus winter.

Off-Peak Energy: Energy normally provided during off-peak periods to supplement or conserve fuel storages (fossil or hydro) of the receiving system.

Emergency: Power (capacity) and/or energy provided on an hourly or daily basis to supplement the generating capability of the receiving system during periods of temporary capacity deficiencies.

Economy Energy: Energy delivered on an hourly basis to effect operating savings when the receiving party has adequate generation, e.g., fuel displacement.

Operating Reserve/Spinning Reserve: Excess generating capacity held available on ten minutes or less notice for use by another system to satisfy its operating reserve requirements.

Treaty Deliveries: Deliveries of energy required or permitted by treaty (such as the Columbia River Treaty).

Transmission Wheeling: Energy transported by an intervening party between a supplier and a receiver.

Storage Transfer: Electric energy transfer "banked" typically in the form of water in reservoir space of another electric utility in the expectation that equivalent electric energy will be returned at a later time.

Adjustment Transfer: An electric power/energy transfer to adjust electric power/energy account balances to compensate for services rendered, to deliver output entitlements, or to deliver upstream or downstream benefits.

SOURCE: U.S. Department of Energy and Energy, Mines and Resources, Canada/United States Electricity Exchanges (Ottawa, Ontario: Minister of Supply and Services, May 1979), pp. 60-63.

TABLE 5.2
BENEFITS TO TRADE

Reliability and Reserve Sharing: Contractual agreements for mutual emergency support between utilities can be used to improve total system reliability or to reduce the operating reserve margin requirement of each utility.

Load Diversity: When two electric utility systems in adjoining areas, or relatively close areas, experience peak loads at different times, the system loads are combined such that generating resources of both systems are better utilized.

Surplus Energy Sales: Energy which is not needed by a system at the time of its availability can be sold to another utility or in the case of hydraulic power, stored in another utility's reservoirs.

Economy Interchange: Economy interchanges occur where the incremental cost of generation on the supplying system of one utility is less than the incremental cost of generation for the purchasing utility. Larger, more efficient generating units or variations in fuel source can cause the generation costs on one system to decrease while the corresponding costs on another system are higher. Therefore, energy can be sold by one utility to another at a cost lower than the purchasing system can generate using its own equipment.

Unit Power Economies Of Scale: Interregional transactions that provide the opportunity for electric utilities to jointly plan the expansions of their systems and allow the installation of larger generating units, resulting in economic benefits to both electric utilities.

Coordinated Operations Scheduling: By coordinating the maintenance schedules of generating units, utilities can ensure that more efficient generating units are operated to their maximum limit.

Use Of Complementary Technologies: Many types of generation technologies complement each other. For example, during low water years, hydro units may provide peaking capacity, while thermal units supply base load energy.

Reduced Fuel Dependency: More efficient operations and increased use of alternative generation technologies made possible through increased inter-utility electricity exchanges can reduce the dependency on strategically important fuels such as oil for generating purposes.

SOURCE: U.S. Department of Energy and Energy, Mines and Resources, Canada/United States Electricity Exchanges (Ottawa, Ontario: Minister of Supply and Services, May 1979), pp. 69-71.

TABLE 5.3
COSTS OF TRADE

Transmission Losses: As inter-utility transactions increase, the distance electric energy must be transported from generation to load center usually increases, resulting in an increase in transmission losses.

Circulating Power Flow: Utility facilities in the northern United States are generally more strongly interconnected than are the transmission facilities between Canada's provinces. If Canadian-United States interconnections are strengthened, there may be increased power circulating flows. These circulating flows load transmission lines, limiting their transfer capability and can cause increased transmission losses. It can have undesirable effects on interconnected utilities that are not parties to the power purchase, sale or wheeling agreements.

Transmission Reinforcement: In order to increase inter-utility transactions, additional transmission lines may be needed. This typically requires that additional inter- and intra-system transmission reinforcement be undertaken which may result in significant costs.

Environmental Impact: More efficient electric generation should reduce total pollution emissions, but geographically redistributing generation also redistributes pollution. Dedicating generation for export may encounter local opposition to constructing facilities, with their concomitant land use and air and water quality impacts.

System Security: The interconnecting of two utilities will normally increase their collective reliability. However, operations control and protection schemes vary from utility to utility and when interconnecting utilities, the control and protective systems of each must be coordinated. Suitable protection equipment to drop loads or to sever interties in an emergency if the system collapses may be needed.

SOURCE: U.S. Department of Energy and Energy, Mines and Resources, Canada/United States Electricity Exchanges (Ottawa, Ontario: Minister of Supply and Services, May 1979), pp. 72-74.

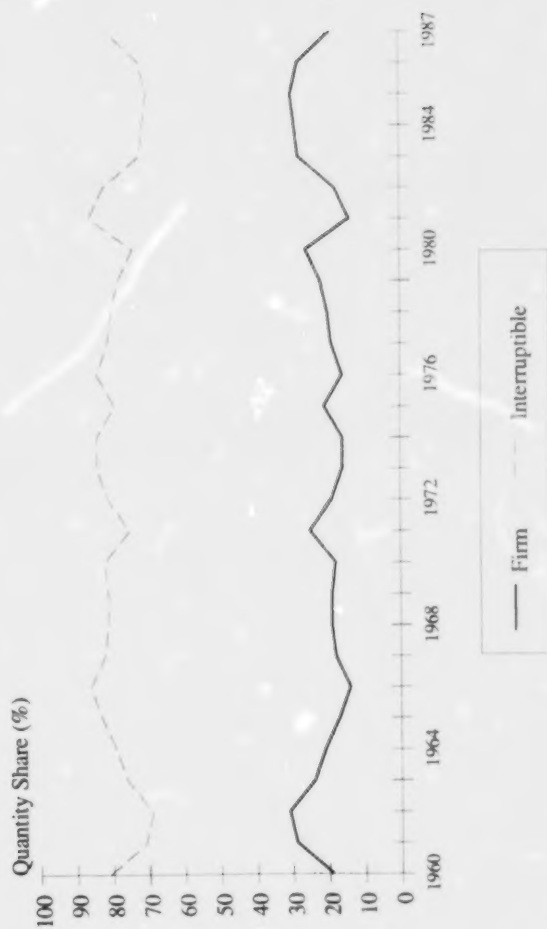
While Canada's initial exports to the United States were not large by present standards, they did account for a major share of Canada's early electricity production. By the 1920s, however, growth in domestic consumption had become the driving force for new hydroelectric developments and Canadian utilities were no longer dependent on the export market. After World War II, the increasing size and sophistication of electric systems contributed to an evolution in the nature of Canada-U.S. power trade. While firm exports still made a contribution to total Canadian sales to the United States, a larger volume of electricity exports began to flow on a shorter-term, more flexible basis as utilities on both sides of the border found that economy sales, emergency back-up, and seasonal exchanges enhanced the reliability and efficiency of their electricity systems.

By 1960, exports to the United States had fallen to less than 5 percent of total Canadian generation. However, in the late-1970s and 1980s, the decline was reversed and the volume of electricity exported by Canadian utilities rose significantly. Most of this new wave of exports to the United States was of an interruptible nature as many Canadian utilities, burdened by excess capacity due to the demand slowdown of the early 1980s, aggressively promoted sales of economy power to neighboring U.S. utilities. In the past several years, a number of utilities--Hydro-Quebec, B.C. Hydro, Manitoba Hydro and New Brunswick Power--have actively sought the type of firm, dedicated contracts that characterized early Canada-U.S. electricity trade.

As shown in Figure 5.1, firm exports have fluctuated between 14 and 31 percent, and interruptible exports have ranged from 69 to 86, percent of total Canadian electricity exports over the 1960-1988 period. Hydroelectric power, the mainstay of Canada's exports to the United States, represented 66 percent of the 29.7 TWh exported to the United States in 1988 (see Figure 5.2).

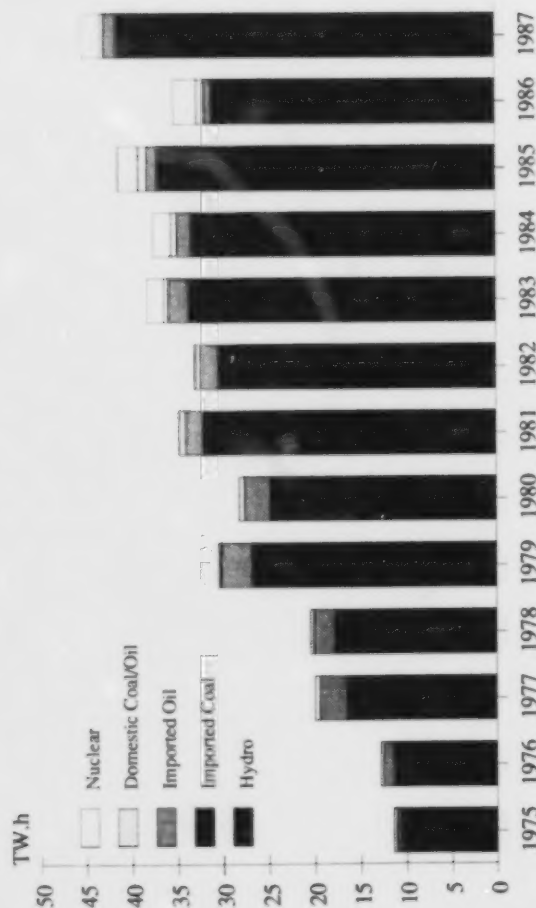
Table 5.4 reports the provincial sources of electricity generation for exports during 1988. Exports from Quebec and British Columbia were generated almost entirely from hydroelectric stations. Exports from Saskatchewan were generated entirely from indigenous coal, while those from Ontario came primarily from thermal stations using imported U.S. coal. In New Brunswick, electricity exports were generated from nuclear, oil and coal sources. The hydro-based electricity exported by New Brunswick was purchased from Quebec and resold. New Brunswick relied heavily on base-load oil-fired and nuclear generation for exports.

Figure 5.1
Electricity Exports to the U.S.,
1960-1987 (percent firm & interruptible)



SOURCE: EMR Canada, Electric Power in
Canada 1987, p. 41.

Figure 5.2
Generation Sources of Canadian Exports
1975-1987



SOURCE: ENR Canada, Electric Power in Canada 1987, p. 42.

Figure 5.3 displays the provincial shares of total Canadian electricity exports for the 1960 to 1988 period. Since the late 1970s, Quebec has been the dominant force in export markets.

TABLE 5.4
ENERGY SOURCES OF ELECTRICITY EXPORTS
1988
(percent)

	Oil	Coal	Nuclear	Hydro	Other ^a
New Brunswick	28	18	40	14	-
Quebec	-	-	-	100	-
Ontario	3	81	2	13	1
Manitoba	-	1	-	29	70
Saskatchewan	-	100	-	-	-
British Columbia	-	14	-	86	-
Canada	5	22	7	64	2

SOURCE: Energy, Mines and Resources Canada, Electrical Energy Branch, Electric Power In Canada, 1988 (Ottawa: Minister of Supply and Services Canada, 1989), p. 40.

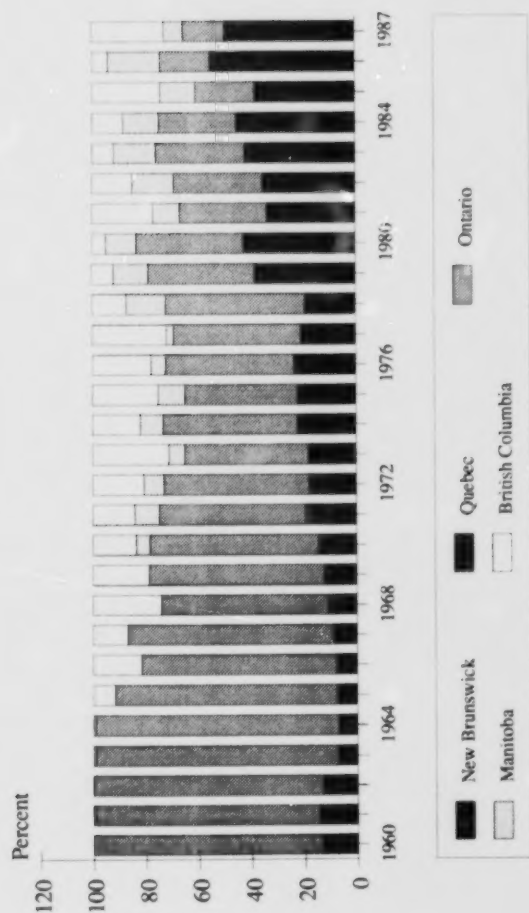
^aRefers to U.S. electricity imports that are subsequently exported.

Export markets in the United States are summarized in Table 5.5. New York state is the most important market for Canadian electricity, representing 35 percent of total kilowatt-hour sales and 35 percent of Canada's total electricity export revenues of \$1.2 billion in 1987. The New England states were also an important market for Canadian electricity exports from New Brunswick, Quebec and Ontario, comprising 28 percent of total kilowatt-hour sales and 41 percent of revenues.

Total Canadian exports represent less than 2 percent of total U.S. electricity demand, a statistic which obscures the reliance on Canadian electricity of certain regions in the United States. Canadian exports comprised 12 percent of total electricity consumption in New York state in 1987, and 13 percent for New England.

There are now over 100 international transmission lines in place to provide for Canada's international trade in electricity. Although most of these lines are quite small, there are 36 bulk power interties rated at 69 kV or higher, with a total transfer capacity of 17 500 MW (see Table 5.6 and Figure 5.4).²

Figure 5.3
Provincial Electricity Export Shares
1960-1987



SOURCE: EMR Canada, Electric Power in Canada 1987, p. 45.

TABLE 5.5
EXPORTING PROVINCES AND IMPORTING
U.S. MARKETS
1988^a

Exporting Province	Importing Market	Quantity (MW.h)	Value (\$1000)
New Brunswick	Maine	3 091 008	110 144
	Massachusetts	1 914 790	108 413
	New Hampshire	43 080	4 031
	New England	4 080	632
Quebec	Maine	903	51
	Massachusetts	278 899	11 932
	New Hampshire	10	1
	Vermont	1 789 215	65 480
	New England	3 931 267	111 407
	New York	5 863 932	156 810
Ontario	Vermont	400 848	14 681
	New York	4 835 344	145 523
	Michigan	382 804	10 248
	Minnesota	3 820	173
Manitoba	Minnesota	659 787	18 546
	North Dakota	63 675	1 619
Saskatchewan	North Dakota	1 475	27
British Columbia	Washington	1 067 410	24 475
	Oregon	2 997 293	42 406
	Idaho	74 310	1 471
	Montana	5 503	116
	California	2 269 248	51 253
	Nevada	41 403	836
	Utah	8 588	191
	Alaska	534	71
Canada	United States	29 729 226	880 537

SOURCE: Energy, Mines and Resources Canada, Electrical Energy Branch, Electric Power In Canada, 1988 (Ottawa: Minister of Supply and Services Canada, 1989), p. 41.

^aExcludes non-cash exchanges.

TABLE 5.6
MAJOR INTERCONNECTIONS BETWEEN
CANADA AND THE UNITED STATES^a

Province	State	Voltage (kV)	Design Capability ^b (MW)
New Brunswick	Maine	1 x 345	600
		1 x 138	60
		5 x 69	155
Quebec	New York	1 x 765	2 300
	New York	2 x 120	300
	Vermont	2 x 120	275
	New Hampshire	±450(DC)	690
Ontario ^c	New York	1 x 230	470
		1 x 230	400
		2 x 230	600
		2 x 345	2 300
		2 x 69	132
		2 x 115	200
	Michigan	1 x 230	535
		1 x 230	515
		2 x 345	1 470
	Minnesota	1 x 120	35
Manitoba	North Dakota	1 x 230	150
	Minnesota	1 x 230	175
	Minnesota	1 x 500	1 000
Saskatchewan	North Dakota	1 x 230	150
British Columbia ^c	Washington	1 x 230	300
		1 x 230	400
		2 x 500	4 300

SOURCE: Energy, Mines and Resources Canada, Electrical Energy Branch, Electric Power In Canada, 1988 (Ottawa: Minister of Supply and Services Canada, 1989), p. 52.

^a35 MW capacity or over.

^bActual transfer capability in practice will be different from design capability.

^cThe transfer capability of several lines may not be equal to the mathematical sum of the individual transfer capabilities of the same lines.

Figure 5.4
Major Provincial and International
Interconnections, 1988



SOURCE: EMR Canada, Electric Power in Canada 1988.

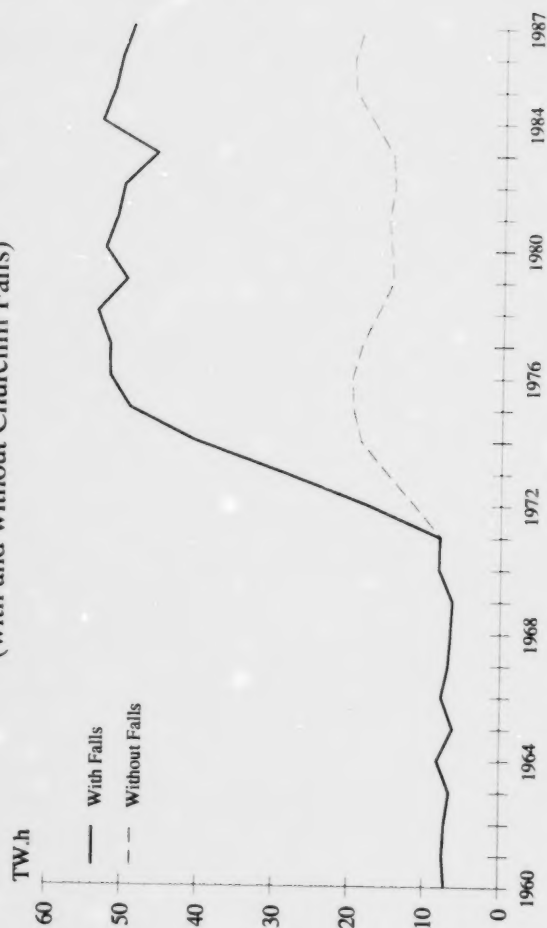
5.2.2 Interprovincial

Historically, interprovincial electricity trade between utilities has occupied a much less prominent position than Canada's trade with the United States. The first major electricity interconnection between Canadian provinces was only completed in 1928--a 230 kV connection between Ontario and Quebec built almost 30 years after the first Canada-United States interconnection. In 1986, a 500-kV interconnection was completed between Alberta and British Columbia. In 1989, the completion of a 230 kV high-voltage, direct-current (HVDC) interconnection between Alberta Power and SaskPower will establish the first cross-Canada electricity grid. This interconnection will enable Saskatchewan and Alberta to share 150 MW of generation resources and permit electric power sales between the two provinces.

Interprovincial trade in electricity totalled 41 517 G.W.h in 1988, significantly above export levels to the United States. However, nearly two-thirds of this was accounted for by a single transaction: the annual sale to Quebec, since the early 1970s, of approximately 30 000 G.W.h of firm energy from Newfoundland's Churchill Falls hydroelectric development. Since this precedent-setting arrangement, there have been a few smaller, long-term interprovincial supply arrangements--most notably trade between Prince Edward Island, New Brunswick and Quebec. However, Canadian utilities for the most part continue to follow an independent approach to the development of future electricity supplies, using out-of-province supply for only short-term or emergency backup. Reliability concerns, employment spinoffs and the comparatively narrow price differentials which exist between the provinces relative to those between U.S. and Canadian utilities are the most commonly cited reasons for this independence in Canadian electric power planning. However, ongoing discussions could soon witness a greater level of interprovincial trade between B.C. and Alberta, Manitoba and Ontario, and Newfoundland, Quebec and Ontario.

Annual Canadian interprovincial electricity trade for the 1960-1988 period is displayed in Figure 5.5. When the Churchill Falls hydro project began producing electricity in 1972, the volume of interprovincial trade increased substantially as Newfoundland sold almost all of its output to Quebec. In percentage terms, interprovincial electricity trade reached a peak in 1975, accounting for about 18 percent of total Canadian generation. However, by 1988, this figure had fallen to 8.5 percent of total Canadian generation.

Figure 5.5
Canadian Interprovincial Electricity
Trade, 1960-1987
(with and without Churchill Falls)



SOURCE: EMR Canada, Electric Power in
Canada 1987, p. 48.

Table 5.7 and Figure 5.4 present the major transmission interconnections within Canada. Currently there are 35 major provincial interties, with a total design capability of about 10 000 MW.³ This compares to the 36 bulk interties between Canada and the United States with a total transfer capability 75 percent greater than the transfer capability between Canada's provinces.

5.3 The Prospects for Trade

5.3.1 U.S. Overview

In the United States, political, economic and environmental problems associated with traditional generating sources have resulted in a virtual halt to construction of new power plants.⁴ Although U.S. electricity demand continues to grow, the use of traditional energy sources such as coal and nuclear in many regions to meet new demand is highly controversial. In addition, the economic risks of building new power plants have increased significantly. Over the last decade, the cost of nuclear plant construction has soared, bringing financial hardship to many utilities. Construction costs for coal-fired plants have also escalated. In addition, the situation is exacerbated by the potential for further regulation to limit emissions which has curtailed planning of many new coal-fired stations. New electric generating technologies offer promise, but many U.S. electric utilities still consider them to be technically unproven. As a consequence, many U.S. utilities in the U.S. view access to Canadian power as an important U.S. supply alternative.⁵

Overtures by U.S. utilities for greater imports from Canada are being actively supported by a number of provinces—notably Quebec, Manitoba, British Columbia and New Brunswick—which are promoting exports to encourage regional economic growth. The magnitude of Canada's undeveloped hydroelectric resources (see Table 5.8) and the low cost of many of these resources compared with U.S. alternatives strongly support an expansion of Canada-U.S. electricity trade.

Roughly three-quarters of U.S. electricity imports from Canada are used to displace imported oil, thereby reducing U.S. reliance on the Persian Gulf and other uncertain sources of energy supply by some 120,000 barrels per day. Since the 1973 embargo, the U.S. Department of Energy estimates that electricity imports from Canada have resulted in savings of over \$7 billion for U.S. utilities compared with the cost of imported oil.⁶

TABLE 5.7
PROVINCIAL INTERCONNECTIONS AT YEAR END
1988

Connection	Voltage (kV)	Design Capability ^a (MW)
British Columbia - Alberta	1 x 500 1 x 138	800 110
Saskatchewan - Manitoba	3 x 230 2 x 110	400 100
Manitoba - Ontario	2 x 230 1 x 115	260
Ontario - Quebec	4 x 230 7 x 120	1 300
Quebec - Newfoundland	3 x 735	5 225
Quebec - New Brunswick	2 x $\pm$ 80 (DC) 2 x 345 2 x 230	700 300
New Brunswick - Nova Scotia	2 x 138 1 x 345	600
New Brunswick - P.E.I.	1 x 138	200

SOURCE: Energy, Mines and Resources Canada, Electrical Energy Branch, Electric Power In Canada, 1988 (Ottawa: Minister of Supply and Services Canada, 1989), p. 50.

^aActual transfer capability in practice will be different from design capability.

TABLE 5.8

DEVELOPED AND ECONOMICALLY DEVELOPABLE
CANADIAN HYDROELECTRIC CAPACITY

Province	Developed (MW)	Economically Developable (MW)
Newfoundland and Labrador	6 300	4 800
Maritime Provinces	1 500	500
Quebec	25 500	19 000
Ontario	7 100	2 000
Manitoba	3 640	5 000
Saskatchewan	700	1 200
Alberta	700	4 400
British Columbia	10 800	17 600
Yukon	80	5 000
Northwest Territories	50	4 200
Grand Total	56 370	63 700 ^a

SOURCES: (1) Alex N. Karas, "Canadian Government Laws, Policy and Exports," address before the American Bar Association's 2nd Joint Conference on Canada/United States Trade in Energy, New York, June 1987, p. 13 and (2) Energy, Mines and Resources Canada, Electric Power in Canada 1988 (Ottawa, Ontario: Minister of Supply and Services Canada, 1989), p. 34.

^aPage 34 of Electric Power in Canada 1988 identifies planning potential less sites that may not be developed for environmental or economic reasons as 46 084 MW of a gross remaining potential of 188 191 MW.

While the majority of Canada's exports to the U.S. have been interruptible economy transactions, the relative importance of these sales is expected to decrease as U.S. utilities commit to long-term, firm power contracts with Canadian utilities. To the extent that U.S. utilities will not be able to satisfy demand growth with existing capacity, they are now considering whether to build new power plants to meet demand or to purchase power from other sources. For utilities along the Canadian border or with access to acceptable wheeling facilities, long-term firm-power purchases from Canada offer an attractive option to new power plant construction.

5.3.2 The U.S. Regional Implications

5.3.2.1 New England

The Northeast, which includes both New England and New York, generates more electricity from imported oil than any other area of the United States. Oil is used for 22 percent of all electricity produced in New York and 36 percent of that produced in New England. While New England utilities have reduced their oil dependency from a peak of 70 percent in 1972, the region's electric utilities are still vulnerable to oil price shocks. Further reductions are difficult given the barriers to construction of new power plants. Coal-fired generation is not an attractive option, as the region is remote from coal reserves and has stringent environmental laws. Moreover, there is a vocal constituency which adamantly opposes the use of nuclear power for electricity generation. Although New England utilities have initiated conservation and demand-side management programs, the extent to which these programs will be successful in curtailing demand growth and limiting the need for new generating capacity is unknown. Consequently, many utilities in this region are looking to Canada for future power supplies.

A number of New England utilities are developing new import arrangements with Canada, most of which will include firm power sales. Quebec's Phase II sales agreement with the New England Power Pool (NEPOOL), for example, will expand Hydro-Quebec's export sales to NEPOOL by an additional 70 billion kilowatt-hours of firm energy from 1990 through 2004.⁷ To facilitate these imports, NEPOOL is building a 130-mile transmission line from the endpoint of its existing Hydro-Quebec interconnection in New Hampshire to Massachusetts. NEPOOL believes that the imported power will save its customers \$2 billion over the life of the contract.

While a number of agreements have been signed and more seem likely, some also appear vulnerable to cancellation. The following examples are, however, indicative of the interest that has been shown in greater trade with the New England region.

- Hydro-Quebec signed a long-term firm power agreement with Vermont Joint Owners in December 1987, providing deliveries up to a possible 500 MW of firm power between 1990 and 2015.⁸
- Nova Scotia Power Corporation and Boston Edison are investigating the feasibility of constructing a 250-mile undersea transmission cable from Nova Scotia to Massachusetts. The proposed line would enable Nova Scotia to export coal-fired power to New England.
- NB Power is negotiating a possible renewal of the agreement to lease some 200 MW of the Point Lepreau plant's capacity for dedicated firm power exports with New England utilities. The current agreement expires in 1991. New Brunswick also recently offered the New England states up to 400 MW of additional firm capacity from provincial coal-fired plants.

5.3.2.2 New York

New York State was the single most important market for Canadian electricity exports in 1987, representing some 35 percent of total Canadian electricity exports and about 12 percent of the state's total electricity demand. Most of these imports displace oil-fired generation.

New York's first long-term power contract was announced in January 1988 by the New York Power Authority (NYPA), which signed a letter of intent with Hydro-Quebec to import two blocks of 500 MW of firm power between 1995 and 2016. NYPA officials estimate that the contract will save New York customers at least \$500 million over its 20-year life.⁹

5.3.2.3 Midwest

The Midwest region includes the states of Indiana, Kentucky, Michigan, Ohio and West Virginia and the states of Iowa, Minnesota, Montana, North and South Dakota and Wisconsin. Currently only Michigan, Minnesota, Montana and North Dakota import Canadian electricity. Overall electricity exports from Canada to the Midwest satisfied just under 3 percent of regional electricity demand in 1987.¹⁰

Both Minnesota, which imports its Canadian power from Manitoba, and North Dakota, which purchases electricity from both Manitoba and Saskatchewan, have discussed new, long-term firm power contracts with Manitoba Hydro. Coal-fired power plants generate more than two-thirds of the Midwest's electricity. Many midwestern coal plants are old, inefficient and more costly to generate power when compared with Manitoba Hydro's hydroelectricity. In addition, the possibility of Congressional action to limit acid rain emissions by requiring utilities to install expensive pollution control devices is delaying decisions on new coal-fired capacity.

Most analysts assert that Canadian electricity exports to the Midwest are unlikely to increase significantly over the next decade, though utilities are expected to move from interruptible to firm deliveries. For example, Northern States Power Co. has an agreement to import 500 megawatts of firm power between 1993 and 2005. This deal was made possible by Manitoba Hydro's decision to advance construction of the Limestone hydroelectric plant. The contract allows Northern States Power to defer construction of a 600-MW thermal plant.

5.3.2.4 West

The Pacific Northwest generates about 75 percent of its power from hydroelectric sources. Federally constructed dams, managed by the Bonneville Power Administration (BPA), account for almost half of the region's generating capacity.

Canadian electricity exports comprised only 3 percent of total electricity consumption for the Pacific Northwest and California in 1987. Of this, California accounted for the bulk, some 13.3 percent of total Canadian exports, Oregon accounted for represented 10.3 percent.

The development of export markets in this region and Canadian access to them is contingent upon many factors, including agreement on coordinated operation of the Columbia River storage facilities and the outcome of negotiations regarding the resale of the Canadian share of Columbia River downstream benefits. In addition, export levels are affected by the price of oil and natural gas in the Pacific Southwest, water availability, and the Bonneville Power Administration's transmission line access policy. The BPA, which controls the high-voltage transmission network extending from the U.S. Pacific Northwest to the California market, has allowed B.C. Hydro access to

these lines only when U.S. utilities are incapable of meeting the demand and additional transmission capacity exists. B.C. Hydro has, therefore, been unable to obtain the secure transmission access that would be required for firm sales contracts in California and other states.

However, recent developments are encouraging. B.C. Hydro's power-exporting subsidiary has finalized its first firm power contract with a California utility, Sacramento Municipal Utility District, for 150 megawatts of firm power. This is the first firm contract that British Columbia has been able to negotiate in U.S. markets. B.C. Hydro is planning two further interconnections with Washington utilities. Ties are planned with Puget Sound Power and Light for 1992 and with Washington Water Power for 1995. Both projects involve 230-kV lines.

In addition, plans are underway for the addition of a third transmission line built by a consortium of 15 municipalities and investor-owned utilities called Transmission Agency of Northern California (TANC). This will increase the transmission capacity of the Pacific Northwest-Southwest Intertie by about 1600 MW by 1993. It is expected that this intertie will increase the availability of hydroelectric power from the U.S. Northwest and British Columbia to displace expensive fossil-fuelled power in California.

5.3.2.5 Synopsis-U.S. Prospects

From the U.S. perspective, the move to additional Canadian electricity imports is driven by low cost, low financial risk and the lack of attractive U.S. supply alternatives. The financial risks involved in large-scale construction programs, the uncertainties of future demand growth, and the technical and environmental concerns that currently plague traditional generating technologies have left many U.S. utilities unwilling to undertake new power plant construction programs. For those utilities in close proximity to Canada, electricity imports are a comparatively inexpensive, low-risk supply alternative. A number of U.S. electric utilities have signed long-term, firm power contracts to import Canadian electrical power and it appears likely that more deals will be signed.¹¹

While the prospects for greater Canadian exports to the U.S. seem assured, there is a considerable range in forecasts. Assumptions vary as to the growth of the U.S. economy and world oil prices. Coupled with uncertainties about the percentage of total electricity

supply met by cogeneration, non-utility generation and DSM programs in the U.S., this has led to a considerable range in forecasts of required U.S. electrical capacity and the subsequent need for and timing of imports from Canada. Recent figures range from Canadian utility estimates for 2005 of 54 TW.h to estimates by the National Energy Board and Energy, Mines and Resources Canada of 48 and 58 TW.h, respectively, for 2005.¹²

Analysis by the U.S. Department of Energy, the National Energy Board and Energy, Mines and Resources Canada indicate that the availability of Canadian electricity supplies will not likely be the limiting factor on future U.S. imports. However, any substantial growth in Canadian exports to the U.S. will require new transmission lines as existing capacity is already heavily loaded. The difficulties which have plagued the electric utilities over the years in obtaining rights-of-way for transmission lines pose a serious impediment to new transmission capacity and enhanced electricity trade both within Canada and between Canada and the United States. It appears, moreover, that these difficulties could be amplified to some degree by an emerging controversy concerning the possible adverse health affects of high-voltage transmission lines.

Growing environmental concerns in Canada could also constrain trade developments. Public concerns over expansion of Canadian nuclear and coal-fired capacity coupled with concerns about cross-border air pollution and global warming are becoming more pronounced in Canada. Moreover, some Canadians are reluctant to exploit Canada's energy resources, particularly if it is to supply firm power to the U.S. market. Political and economic concerns in both countries could also limit expansion of Canada-U.S. trade developments. These issues are discussed more fully in Section 5.4.

5.3.3 Interprovincial Trade

The constraints to greater interprovincial trade are comparable, in many respects, to those affecting increased trade between utilities in Canada and the United States. Paramount among these are questions of technical reliability, limited capacity of the existing transmission system and the siting of new transmission interties.

Enhancing interprovincial trade and coordination raises the issue of approval of right-of-way for new transmission lines and transmission line upgrading. Many of Canada's electric utilities have experienced considerable opposition to the siting of major transmission

lines in the past decade and this seems destined to continue, as the public's increasing concern with the potential adverse health affects of high-voltage transmission lines compound concerns over the aesthetics of these lines.

To some degree, political and regulatory barriers also limit interprovincial transfers of electricity. For example, the Ontario Select Committee on Energy recently recommended that Ontario Hydro examine *all possible options* prior to its consideration of importing power from other utilities: "No major firm purchase of power from neighboring provinces should be pursued until maximum efforts are made to utilize the cost effective indigenous resources of Ontario, e.g., demand management, existing generation, private generation and remaining hydraulic."¹³ Given the uncertain impact of DSM noted earlier, it seems counter-productive that trade be given a back seat to, as yet indeterminate, cost-effective DSM.

While it is unlikely that interprovincial electricity exchanges will exhibit major gains over the next decade, prospects for greater trade do seem more promising in light of the following recent developments:

- Ontario Hydro has signed a 200-MW firm power purchase with Manitoba Hydro and is discussing an additional 1000 MW, 20-year firm power purchase;
- In August 1989, the premiers of Ontario, Quebec and Newfoundland agreed to consider ways of cooperating in the development of new hydroelectric power sites in Labrador. In total, the sites identified could be developed to produce an additional 2900 MW of power; Upper Churchill - 500 MW, Muskrat Falls - 700 MW and Gull Island - 1700 MW;
- New Brunswick struck a deal with Hydro-Quebec to supply up to 3000 GW.h of firm electricity per year, starting in 1988 and extending until 1992, with a further 2000 GW.h per year of energy available in 1993 and 1994;
- Quebec and New Brunswick recently signed an agreement to provide Prince Edward Island with 50 MW of firm energy until 1994. New Brunswick will buy the power from Quebec and resell it to Prince Edward Island at a price sufficient to cover the costs of wheeling;
- When completed, a 150-MW DC electrical interconnection between Alberta and Saskatchewan is expected to

allow SaskPower to postpone the construction of a limited amount of gas-fired peaking capacity, relying instead on short-term back-up power from Alberta. The line is scheduled to go into service in October 1989; and

- During 1987, the Alberta and B.C. governments established a task force to assess the potential economic benefits from coordination of the BC Hydro and the Alberta Interconnected System (AIS).¹⁴ Results indicate substantial benefits from further coordination between the two systems. The expected value of the potential benefits (1990-2010 Net Present Value) ranges from \$600 million for fully coordinated operation to as high as \$1.2 billion for fully coordinated operation, planning and construction. These results identify generation benefits only. Additional study will be carried out in the following areas:
 - (i) Transmission systems in both provinces will be examined to further identify costs, capability and benefits of incremental additions of transmission capacity;
 - (ii) A study will be undertaken to confirm the potential of the coordinated resources of the two systems to supply a large firm export load;
 - (iii) Sensitivity analysis will be used to evaluate the impact of future uncertainties such as load growth, fuel costs and financial parameters on the potential benefits of generation coordination; and
 - (iv) Studies will be undertaken to evaluate incremental increases in generating coordination.

The prospects for firm power exchanges between Canadian utilities are, to a significant degree, intertwined with the development of trade opportunities in the United States. This results from the fact that the cost of U.S. generated power is higher than that in Canada, making U.S. destinations the principal focus for Canadian utilities interested in maximizing revenues.

To account for this interdependency, the Canadian Energy Research Institute and the Alberta Research Council developed a generation planning model which permits examination of the costs and benefits of greater electricity trade within Canada and between Canada and the United States. This model (ELGEM - see Volume II) accounts for differences in peak and energy forecasts in Canada and

the United States together with the difference in the cost of generation and transmission between the various regions.

The following section examines some of the significant constraints to trade before presenting the results of a number of ELGEM modelling scenarios, their implications for electricity developments, and the potential savings resulting from more coordinated electric power planning.

5.4 Constraints to Trade

While opportunities exist for increased interregional electricity trade--both export and interprovincial--there are a number of uncertainties and constraints which will limit the extent to which these benefits are realized.

The single most important barrier to greater trade appears to be new transmission capacity. Since new transmission lines are sometimes blocked by economic, safety, aesthetic and environmental objections, not all of the new capacity required to maximize electricity trade is likely to be developed. The discussion below speaks to technical considerations in transmission planning, the health effects of high-voltage transmission lines, the wheeling issue and various political and economic factors which could act as trade impediments. The health effects of high-voltage transmission lines are treated in isolation from other siting and environmental concerns, as this issue is the newest constraint to construction of new transmission capacity--the vital ingredient to greater trade. While a number of other "trade and environment" considerations are important to future electric power trade (e.g., land and water use impacts of hydroelectric projects, aesthetic impacts), these are problems which have impacted on transmission line right-of-way planning for many years.

5.4.1 Technical Considerations

The bulk power electric transmission systems in North America have evolved over the years into complex, highly integrated networks of "interconnections." Today in Canada and the continental United States, there are four major interconnections: Western Interconnection, Texas Interconnection, Eastern Interconnection and Hydro-Quebec. Each interconnection encompasses large geographic areas and many individual utilities. The boundaries of these interconnections are shown in Figure 5.5. For various reasons, it is impractical or impossible to interconnect the four interconnections with alternating current transmission lines. High-voltage direct current (HVDC)

ties are therefore used to transfer electric energy between the interconnections. Within each interconnection, individual utilities are connected mainly by alternating current lines.¹⁵

One characteristic of an interconnected electrical power system is that all generators must operate in synchronism. Another is that the total output of these generators plus the power flows on interconnections must equal the instantaneous electric power demands of all customers plus losses. Reliability dictates that the bulk power transmission system be designed and operated such that it can always accommodate the redistribution of flows resulting from the more likely outages.

Both the interconnections with adjacent utilities and the supporting internal transmission system must be sized to accommodate routine and emergency transfers of energy between utilities. In addition, there must be sufficient redundancy of transmission lines such that no single transmission route will be depended on to carry a disproportionate share of any power transfer.

The flow of electricity is very difficult to control in a transmission network since it takes the path of least resistance and is affected by relative impedances and loadings of various paths. Therefore, the transfer of power between two utilities often involves the use of many different transmission routes as power will actually flow over all possible paths. This phenomena is termed parallel path flow or loop flow. Some of the power transferred will actually flow through the transmission lines of utilities that have not participated in the energy transaction, leading to a decrease in their transmission reliability. In some cases, the reliability of utilities hundreds of miles away can be adversely affected.¹⁶

As a consequence of the interdependency of transmission systems, the impact of a proposed line on the reliability and stability of the transmission system requires detailed simulation modelling of the entire transmission system. To assess the reliability impact of a project, the North American Electric Reliability Council (NERC) follows the standard that the system must be able to withstand the sudden loss of any of the following single components: the entire output of any single generating station; all transmission lines out of any single terminal; all transmission lines on a single right-of-way; or all the load at any single load centre. Each of these events will create a sudden shock wave of power that propagates through the transmission

network as the system adjusts to a new steady state. If not controlled, these events can cause expensive cascading blackouts.

The transmission networks in the United States were originally built to deliver energy from generating plants to load centres, to provide paths for that energy during facility outages, and to provide emergency support from neighboring systems. U.S. utilities have also utilized the transfer capability of the transmission network to make economy sales and purchases of capacity and energy with other utilities on an intraregional and interregional basis. In response to the fuel/cost differentials between U.S. utility systems, the growth in power transfers and intersystem sales has accelerated in recent years. For the period from 1961 to 1983, interchange transactions increased seven-fold and wheeling transactions increased twelvefold. This compares to a threefold growth in sales to ultimate customers over the same period.¹⁷

5.4.2 Capacity

As a result of the growth in power transfers and intersystem sales, U.S. transmission lines have been loaded to near-maximum reliability limits in many regions. This has led to increased system vulnerability. To increase reliability, existing transmission facilities must be upgraded or new ones must be built. Constructing new transmission lines would increase the capability to transfer economy energy and, at the same time, increase the capability to respond to emergencies and improve overall reliability and economy of operation. Unfortunately, there are major impediments to building new transmission lines. These include:

- difficulty in obtaining right-of-way;
- lengthy transmission licensing procedures, which generally include an examination of health affects;
- conflicting jurisdictions among local, state and federal agencies; and
- the uncertainty of the long-range economic benefits.

The importance of additional U.S. transmission capacity is critical to enhanced electricity trade with Canada, as new transmission capacity is needed to ensure that Canadian exports do not adversely affect the ability of U.S. utilities to transmit energy reliably and economically.

In New York State, for example, improving intrastate transmission lines is necessary in order to take full advantage of the capacity of Canadian interconnections. The New York Power Authority has a transmission interconnection with Hydro Quebec that can transmit up to 2350 MW of power, but the intrastate transmission system cannot handle imports of this magnitude. Thus, New York utilities are reinforcing the transmission lines from central to southeastern New York and building a new transmission line across Long Island Sound. When both of these projects are completed, Canadian imports will be able to grow.¹⁸

In summary, transmission interties in the United States cannot currently accommodate greatly increased electricity imports from Canada. Substantial investment in transmission upgrading and new transmission capacity is required before Canadian imports can grow significantly. However, the impediments to constructing new transmission lines in the United States are formidable. For example, NERC has reported delays of up to 15 years in the in-service dates of transmission lines.¹⁹

5.4.3 Reliability

In evaluating the relative merits and possible limits to Canadian electricity imports as a source for U.S. needs, it is important that the effects of electric energy transfers on non-importing utilities be accounted for. As there can be significant impacts on remote utilities, the true cost of transmitting power must include both the increased production costs placed on remote utilities and the costs of transmission grid enhancements which are designed to reduce these impacts--both those undertaken within Canada and the United States.

Many U.S. electric utilities, particularly those in the eastern states, are concerned that additional transmission interconnections with Canadian utilities and expanded imports will create reliability problems. For example, utilities have expressed some apprehension that additional interconnections with Hydro-Quebec could jeopardize the reliability of service throughout the eastern United States, as Quebec has experienced many system-wide collapses and its record is poorer than that of any other interconnected network within the NERC. The concern stems from the fact that the loss of Hydro-Quebec generating units or HVDC facilities delivering energy from Quebec could result in the sudden interruption of all or a portion of Quebec's exports. The loss of imports from Hydro-Quebec could cause large

changes in transmission line flows through remote utilities which could in turn compromise system reliability.²⁰

To account for reliability concerns, an integral component of Hydro-Quebec's Phase II export program is the concept of isolating the generation that feeds the 2000-MW HVDC tie to New England from the Hydro-Quebec network. If it operates as planned, the shutdown of Quebec's system would cause 2000 MW of Hydro-Quebec generation to be isolated on the Hydro-Quebec/New England Phase II line. However, the outage of the Phase II line would interrupt a maximum of 2000 MW of generation supply to the Northeast. As this amount is larger than the largest generating unit in the Eastern Interconnection, voltage and overloading problems on certain transmission lines would occur. While Hydro-Quebec is undertaking programs to improve its performance, U.S. utilities limit their imports from Quebec to the Northeast at any given time to the amount that neighboring regions could provide should the Hydro-Quebec system crash. They continue to design their system to accommodate a shutdown as a credible contingency given Hydro Quebec's history of system-wide failures.

In summary, if Canada-U.S. electricity trade is to grow substantially, construction of new transmission capacity within the United States and between the two countries is essential. Various technical and reliability parameters will also exert an important influence on the timing and extent to which trade flows increase in the future.

5.4.4 Health Effects of High-Voltage Transmission

A number of health and environmental issues promise to become more important in electricity trade. The newest involves possible adverse health effects of high-voltage transmission lines. The areas of concern are the oscillating electric and magnetic fields that exist in the space around power lines, wiring or appliances. Health-related concerns could well have a major impact on the future level of exports as virtually all electricity trade between Canada and the United States occurs over high-voltage lines.

Until recently, studies of the health effects of high-voltage transmission lines have yielded results that have either been inconclusive or shown no harm. However, a recent study by the New York State Health Department (July 1987), known as the Power Lines Project, has significantly increased public awareness about the

contention that transmission lines cause adverse health effects. This project was initiated in 1981 following a protracted controversy over the construction of two high-voltage transmission lines. The Power Lines Project consisted of 16 independent studies on the effects of electric and magnetic fields on biological systems. While 15 of the 16 project studies found no evidence of a link between exposure to electromagnetic fields and adverse health effects, one study found a possible association between residential magnetic fields and certain childhood cancers.²¹

While the results of the Power Lines Project indicate some reason for concern, considerable scientific uncertainty remains. Assessing the risk of health affects related to exposure to electromagnetic fields is complicated, as there are multiple sources of exposure to these fields. While transmission lines have been the focus of public opposition, research indicates that household and workplace appliances provide at least as much exposure as power lines.²² Scientists generally agree that a causal relationship has not been established between exposure to electric and/or magnetic fields and the incidence of cancer or other adverse health effects. They contend that if adverse health effects result from exposure to electromagnetic fields, they appear to require long-term exposures and to occur rather rarely.²³

Nevertheless, the findings of the New York Power Lines Project have increased public opposition to high-voltage transmission lines. Those opposed to new construction argue that these projects should not be undertaken until there is ample evidence that public safety can be assured. In fact, a number of U.S. regulatory bodies have been swayed by increasing public concern and have restricted line voltage in densely populated regions. At least six states have reacted to public concerns by placing limits on the field strengths of transmission line rights-of-way: Minnesota, Montana, New Jersey, New York, North Dakota and Oregon.

Indicative of the more typical finding is a recent decision by Alberta's Energy Resources Conservation Board.

The Board also concludes that considerable biomedical research has been conducted to date and that it has not demonstrated harmful biological effects caused by 60-Hertz sinusoidal EMFs due to high-voltage transmission lines. Epidemiological and laboratory research currently underway, or to take place in the future, could modify this conclusion. However, while the Board supports the continuation of such research, it cannot base its decision concerning power line

placement in the present case on speculation that health effects could possibly be demonstrated by future research.

The Board, therefore, concludes that there is no evidence of health effects of the proposed 240-kV transmission line that would justify denial of the application. On the same basis, the question of health effects should not influence its decision on the appropriate location of the line.²⁴

While the jury is still out, all parties agree on one thing--the potential for harm to human health warrants considerably more epidemiological and laboratory research. In the United States, the Electric Power Research Institute is conducting research in a number of areas to improve exposure assessment and explore the occurrence and mechanisms of effects in animals and cells. In Canada, Hydro-Quebec, Ontario Hydro, the Canadian Electrical Association and Canada Health and Welfare are involved in various research programs to better understand the potential health effects of electric and magnetic fields.

While scientific findings remain inconclusive, many expect that increasing public concern with the potential health-related effects of high-voltage transmission lines will compound the difficulties involved in the siting and construction of new transmission lines. As a consequence, the potential for greater Canada-U.S. electricity trade could be restricted. These difficulties will be exacerbated to some degree by growing public concern within Canada with the environmental damage caused by large hydroelectric and fossil-fuelled projects and issues related to construction of generating and transmission facilities dedicated to export.

5.4.5 The U.S. Debate Over Canadian Power Imports

The move to greater U.S. imports from Canada, coupled with a shift to long-term, firm power purchase arrangements, has drawn U.S. national attention to the implications of greater Canadian electricity trade. The questions posed include--what share of U.S. demand should be satisfied from Canada? will U.S. utilities have enough power when import contracts expire? does the trend toward greater reliance on Canadian electricity imports have national security implications? and does the pricing of Canadian electricity exports contain any elements of subsidization? The U.S. coal lobby, concerned about

loss of market share, has been one of the most vocal opponents of electricity imports from Canada.

Among others, the United States General Accounting Office (GAO), the United States Department of Energy (DOE) and Harvard University have examined U.S. concerns over the importation of greater amounts of Canadian electricity in the future.

The GAO concluded:²⁵

- that the price paid for imported power results in cost advantages to domestic utilities and consumers; and
- current purchases of Canadian power do not exceed levels considered acceptable by utility and regulatory officials.

The GAO stated that utility and regulatory officials expressed no concern over the use of imports as long as domestic power plants are available to back them up. A reasonable level of imports was felt to be in the range of 15 to 20 percent of the purchasing utility's generating requirements. The decision to rely on imports beyond this level would depend on the utilities' analyses of the future uncertainties associated with building domestic power plants and the extent to which existing limitations to moving power between regions in the United States have been resolved.

In December, 1987 the DOE released a wide-ranging analysis of the practical and economic potential for imported power from Canada.²⁶ This study concluded:

- Provided that utilities have incentives to build their own power supplies, imported power can enhance the nation's security by diversifying away from unstable energy supply sources such as the Persian Gulf. Hydro power from Quebec and Newfoundland, as well as nuclear power from Ontario and New Brunswick and coal-fired power from Ontario, can displace expensive U.S. coal-fired generation.
- Most Canadian hydro power would remain economic even if Canadian power were assessed under U.S. tax regulations. U.S. tariffs or other trade restrictions would be counterproductive as Canadian power would continue to be economically competitive with U.S. electricity sources. A tariff would impose additional costs on both Canadian utilities and U.S. customers without significantly altering the level of U.S. electricity imports from Canada.

- As power imports become firmer and longer in term, Canadian power is increasingly seen as a reliable source of electricity in the United States.

Provided utilities can build adequate transmission links and reinforcements, increased imports and interregional power transfers can help meet U.S. regional power needs. However, increased imports will require an enhanced transmission grid. In Canada, particularly Quebec, transmission reinforcements will be needed so that increased imports do not increase the likelihood of costly power blackouts in the United States. Additional transmission capacity in the United States will also be required to ensure that Canadian imports do not adversely affect the ability of U.S. utilities to transmit energy reliably and economically.

Harvard University's Energy and Environmental Policy Center concluded that U.S. consumers derive substantial benefits from their access to Canadian electricity supplies and that it would be a costly mistake for the United States to reduce or eliminate that access.²⁷

The study authors asserted that expansion of transmission capacity between Canada and the United States will be difficult. Environmental pressures in the U.S. will make it harder to site and build new links between the Canadian border and U.S. load centres, particularly where additional transmission capacity is sited in areas which are not beneficiaries to imported power. Any significant rise in imports will, moreover, increase the cost of maintaining U.S. reliability standards and consequently reduce the competitiveness of purchasing power from Canada. As available sites for new transmission capacity are used up and the cost of ensuring system reliability increases, the total cost of Canadian power will begin to increase relative to U.S. alternatives. This will eventually force Canadian utilities to choose between lowering their prices or foregoing U.S. export sales.

In addition, the study noted that political pressures may limit the rate of growth of electricity exports from Canada, as state governments may be reluctant to allow utilities to become "overly dependent" upon Canadian imports. The report also contends that Canadian politicians will scrutinize the growth in Canadian electricity exports and that some political pressure may eventually be exerted on Quebec to export "internally" within Canada over the next few decades. Uncertainty over the timing of additional capacity needed for

Canadian domestic requirements could also restrain the growth of new export contracts to the U.S.

In summary, most studies of the impact and desirability of increased U.S. electricity imports from Canada have concluded that U.S. consumers derive substantial benefit from access to Canadian energy supplies and that tariffs or other trade restrictions would be costly for American consumers. However, some counter that as the level of Canadian power imports grow, some states can be expected to initiate "security of supply" actions and thereby limit imports so they do not become "overly dependent" on a foreign energy source.

5.4.6 The Wheeling Issue

One of the most controversial and complex issues affecting the future of electricity trade is the issue of electric power wheeling--the transfer of electricity between two parties over a third party transmission network.

The issue of power wheeling has gained increased prominence in recent years, particularly in Eastern Canada, due to the rising cost of power and restricted access to less costly power sources. Nova Scotia, Newfoundland and Prince Edward Island have all explored various means to break the transmission monopoly positions of utilities in New Brunswick and Quebec. In mid-1988, for example, the PEI government announced its bid to break its captive market status with the New Brunswick Power Commission in a 6-year electric power agreement with Hydro-Quebec. The possibility of linking the island with either Quebec or Nova Scotia by undersea cables to avoid the wheeling charges that New Brunswick applies to power it transmits from other sources has also been under investigation. Nova Scotia Power Corp. has also been frustrated by its inability to get large volumes of power through New Brunswick at a reasonable price and has explored the use of an undersea cable for a major project dedicated to supplying power to New England.

In Newfoundland, the wheeling issue has been of paramount importance for some time. Newfoundland's geography places severe restrictions on its ability to trade electricity with other provinces or with the United States. Its only common land border is shared with Quebec, which until now has refused to allow Newfoundland to transmit its power through Quebec to other markets. It is possible that hydroelectric power generated in Labrador could be delivered to the island of Newfoundland, via an expensive 1000-kilometre transmission

line, but a possibility more appealing to Newfoundland is wheeling Labrador power to the lucrative export markets of the northeastern United States or to Ontario. However, this would require the cooperation of Hydro-Quebec and the Quebec government. Until recently, the prospects for an agreement with Quebec seemed remote. However, the two sides are still negotiating the possible joint development of the Labrador sites--Gull Island and Muskrat Falls--as well as possibly adding a twelfth generating unit to the existing Churchill Falls development. The electricity produced by these projects would be delivered in part to Newfoundland, and in part to Quebec for subsequent resale to export markets or to Ontario.

The issue of transmission access is important as wheeling could help to promote the equalization of power costs, greater economic efficiency and reduced environmental impacts. However, there are technical difficulties associated with increased wheeling and these tend to become more critical and binding the more complete the access becomes. Supporters of the status quo note that the existing transmission system was not constructed to provide trade opportunities. Instead, utilities have tended to size their transmission systems to meet their own needs in minimizing generation capacity requirements and ensuring reliability. Consequently, the demand for wheeling could create new transmission capacity shortages, necessitating substantial investment in strengthening and reinforcing existing lines and investment in new capacity.

As noted earlier, the impact of a wheeling transaction can extend to adjacent utilities who are not part of the transaction. Loop flows occur because the electricity flows along the path of least resistance rather than along the contract path. This can reduce the transfer capability of the lines and may increase the losses on the system. Heavier loading implies increased technological complexity and a greater need for cooperation among participants.

The issue of the appropriate charges for wheeling is complex, as the cost of providing transmission service varies with the type of service provided. While short-run costs are appropriate for short-term energy transfers, firm power agreements may require an expansion of the transmission network. Therefore, long-run charges which cover the cost of building new capacity may be more appropriate for this type of service. However, this would present some difficulties since the allocation of total costs to various types of services is somewhat ambiguous.

While appropriate pricing of transmission services is crucial to all parties to the wheeling transaction, the wheeling issue may become largely meaningless if new transmission capacity cannot be built. As noted earlier, the constraints affecting the siting and licensing of new transmission lines are formidable. In fact, many observers point to this difficulty as being the most critical issue facing the North American electric utility industry today.

In general, the issues involved in transmission access and wheeling can be broken down into three categories—technical, economic and institutional. Opponents of increased access, those who favour voluntary wheeling, are quick to call attention to potential technical problems involved in any change, particularly the issue of reduced reliability. Wheeling proponents counter by pointing to the potential increases in overall economic efficiency resulting from greater access to power markets. The technical issues involved with increased transmission access appear to be a function of the number and magnitude of power transfers and the capacity of the existing transmission system. For example, the advent of power pools and coordinated dispatch centres in the United States has made wheeling bulk power an important component of U.S. utility planning and systems operation. *The only real issue then is not whether wheeling is technically feasible, but rather the establishment of required transmission capacity and appropriate charges for the wheeling of electric power.*

5.4.6.1 Arguments For and Against Wheeling

In June 1987, a National Energy Board panel issued a report for the federal government's consideration dealing with various options that could be pursued to simplify and reduce the regulation of electricity exports. The report was based upon submissions from electric utilities, governments, associations and public interest groups. Among other issues addressed, the report offered an overview of the arguments for and against the NEB's possible promotion of power wheeling.²⁸

Not unexpectedly, views on this issue ranged from strong opposition to any NEB involvement to strong support for such involvement. Most parties who were opposed to increasing the NEB's authority to order transmission access felt that utilities which own transmission facilities should have the authority to decide how those facilities should be used. They argued that transmission access to

allow for wheeling of exports should be freely negotiated between the parties concerned. For example, Hydro-Quebec asserted that it would be unjustified and unfair to force a utility that had assumed the economic and financial risk associated with construction and operation of these types of facilities to provide transmission access to another utility, especially by some arbitrary process.

NB Power, Ontario Hydro and B.C. Hydro (all exporting utilities) stated that their transmission networks are a limited resource and that transmission access should only be provided to the extent that the risks and costs are shared. B.C. Hydro and NB Power also argued that a province's proximity to market was as much a provincial natural resource as was the geology and topography which supplies the source of energy to be sold. As a consequence, provinces should therefore exercise control over the use of that resource. Ontario Hydro added that the primary use of its transmission system should be to serve domestic loads and that domestic market, inter-utility transactions should be given priority over the use of its facilities by others for wheeling power to export markets. The Ontario Ministry of Energy maintained that transmission access should be by mutual agreement, subject only to provincial government approval.

Among the non-exporting utilities, those in Newfoundland and Alberta argued that the NEB should have authority to regulate inter-utility transfers and wheeling over interprovincial power lines in the same way that the NEB currently exercises jurisdiction over inter-provincial pipelines. They stated that the NEB should be given the necessary authority to order an intervening utility to provide transmission access to a utility in another province, provided that the intervening utility was fully compensated for all its costs.

The panel noted that there are two ways in which utilities without direct access to export markets could currently seek to gain such access: (1) a utility may seek access to the transmission facilities of another for the purpose of having its surplus wheeled through the utility's facilities to export markets; or (2) a utility may gain access to the export market through a purpose-built line that would traverse another province.

5.4.6.2 Transmission Access to Wheel Electricity Exports

The panel noted that the NEB currently does not have authority to order transmission access for the purpose of wheeling

power for exports and that utilities must seek this type of transmission access themselves through voluntary negotiation.

The panel raised a number of technical, economic and financial questions that would arise with mandatory wheeling: (1) Does the utility providing the wheeling service have spare capacity or would some transmission network reinforcements be required? (2) What financial arrangements should apply in cases where additional transmission facilities are required? (3) What are the appropriate wheeling charges? (4) Should charges include compensation for the wheeling utility's "lost opportunity" in the export market, if any?²⁹

The panel suggested that the primary responsibility for negotiating wheeling arrangements should rest with the utilities involved. It noted, however, that it may be desirable to introduce regulatory changes providing authority that, failing such agreements, utilities could seek to have their power for export wheeled over an intervening utility's transmission lines. However, since electricity flows through the path of least impedance, it would not likely be possible to confine power wheeled for export to a particular line on the wheeling utility's system as the wheeled power would flow through many circuits within the network. This could cause technical difficulties, creating costs for the wheeling utility and it would be reasonable to expect recovery of these costs from the party whose power is being wheeled. While stating that utilities requiring wheeling service should pay the full costs incurred, the panel noted that some wheeling costs can be quantified with certainty, whereas others cannot. A major stumbling block to wheeling arrangements, for example, is the question of compensation for the "lost opportunity" to the wheeling utility. Exporting utilities generally favoured such charges, while those seeking transmission access for export wheeling purposes stated that there should be no compensation related to the loss of possible export markets.

The panel asserted that wheeling of interruptible exports is significantly different from wheeling firm exports since the wheeler can control the power flow through his system at all times and thereby respect any operational limits. The panel stated that utilities should negotiate wheeling arrangements for interruptible energy exports as there can be opportunities for both the wheeler and the party requesting wheeling, without appreciable costs to either party.³⁰

5.4.6.3 Transmission Access Through a Purpose-built Line

Under present circumstances, if utilities fail to agree on transmission access for wheeling of exports, an electric utility might gain export access through the construction and use of a purpose-built line traversing an adjoining province. The NEB now has jurisdiction over international power lines, which are defined in the NEB Act to mean facilities constructed or operated for the purpose of transmitting power from or to a place in Canada to or from a place outside Canada. The NEB Act would appear to cover export-dedicated lines originating in one province and traversing the territory of another province en route to the export market. Accordingly, any utility wishing to construct a purpose-built line for exports through an adjoining province could apply to the NEB for a certificate of public convenience and necessity. If it were found to be in the public interest, the NEB could grant the authorization and approve the route.

The panel stated that it would be preferable if the construction of such export-oriented facilities were undertaken with the agreement of interested utilities and provincial governments. However, if such facilities meet the definition of an international power line in the NEB Act, they are subject to final regulatory approval by the Board.

The Panel concluded its discussion of wheeling in recommending various options that might be considered by the federal government.³¹

- (i) Amend the Act to provide for federal regulation of transmission access to wheel electricity exports.
- (ii) Amend the Act to allow for federal regulation of transmission access to wheel electricity exports but provide for relevant sections to be proclaimed at a later date if utilities fail to reach an agreement.
- (iii) Retain the status quo. The Board would continue to rely on utilities to negotiate transmission access agreements for the wheeling of electricity for export purposes.
- (iv) Amend the Act to make explicit the NEB's jurisdiction over the construction and operation of export-dedicated lines traversing an adjoining province.

- (v) Amend the Act to make explicit that the Board does not have jurisdiction over the construction and operation of export-dedicated lines traversing an adjoining province.

5.4.6.4 Synopsis

While considerable time has been devoted to the wheeling question, there have been no changes made or proposed which would alter the existing regulation of electric power wheeling in Canada. The status quo model currently applies and electric utilities must seek transmission access through voluntary negotiation.

In many respects, the status quo model is a pragmatic option as it is premised upon mutual benefit of the directly concerned parties. This option is politically expedient and yet offers a mechanism for the export of power through an intervening province by means of application to the NEB for a purpose-built transmission line. It also recognizes the complexities in applying an appropriate charge to wheeling services by leaving the technical and arbitrary assignment of costs and service provisions to negotiation between those who would be directly affected by the wheeling transaction.

A case in point is the recent discussions between Quebec, Ontario and Newfoundland to jointly develop and transmit power from Labrador. All parties would share the economic benefits of using Labrador's hydroelectric potential and Quebec's transmission facilities. While this is not a clear-cut example of wheeling, it does point to some of the benefits that are possible from joint development of generation and transmission capacity. The only thing appearing to stand in the way of more of these developments and "true" wheeling transactions is the recognition that many such transactions would be mutually beneficial for the seller, wheeler and electric power purchaser. This statement is, of course, equally valid for electricity trade between contiguous provinces.

5.5 Modelling Interprovincial and International Electricity Flows

In order to evaluate the potential benefits of increased trade and greater coordination in Canadian electric power planning, the Canadian Energy Research Institute and the Alberta Research Council (ARC) developed a model (ELGEM) of optimal electricity trade flows within Canada and between Canada and the United States. Detailed

model assumptions and data, together with the results of various simulations are provided in Volume II.

ELGEM provides a comprehensive analytical framework for regional electric power planning over the 1988 to 2009 period. Canada is disaggregated into eight regions, with the Maritime provinces considered as one region and all other provinces treated individually; the United States is divided into four potential market regions. Electric power demand for each region forms part of the input data and is exogenous to the model. Electric power forecasts for the various regions were taken from Canadian electric utility forecasts (see Chapter 2) and from the United States Energy Information Administration's electricity model.

The ELGEM model produces a capacity addition schedule that minimizes the present value of the cost of meeting forecast electricity demand in each region, given the availability and costs of all perceived generating options. Two constraints must be satisfied: (1) there must be enough dependable capacity to meet the forecast average load; and (2) there must be enough peak capacity to meet the forecast peak requirements, plus a specified reserve margin. The model has perfect foresight and therefore represents an upper limit on what can be achieved, given the conditions specified by the user. As this particular study was primarily concerned with interregional trade in firm power and energy sales within Canada and between Canada and the United States, the model accounts for peak and energy sales only. It does not account for short-term, economy sales of electricity stemming from unexpected surpluses or deficits and noncoincident daily peaks arising from time zone differentials. If these were accounted for, the benefits of increased interregional electricity trade would be even greater than in the figures presented below.

In the ELGEM model, only transmission links between Canadian regions to other Canadian regions and to contiguous American regions are considered. The model seeks that schedule of capacity and transmission additions that would minimize the cost of meeting forecast demand for electricity in the United States and Canada, subject to any non-economic or political constraints that may be imposed on the modelling system.

5.5.1 Trade Scenarios

The reference case is represented by Case 1 (No New Trade), shown in Table 5.9.³² No additional trade transactions are assumed to

TABLE 5.9
ELGEM TRADE SCENARIOS

Case	1	2	3	4
Scenario	No New Trade	Full Trade	No New Exports ^a	Full Trade
Discount Rate (%)				
Generation	5	5	5	5
Transmission	5	5	5	5
Ontario Nuclear/Coal Ratio	0.5	0.5	0.5	1.0
Objective Function ^b	1619	1593	1616	1593
NPV Trade Savings ^c				
Canada	0.0	0.13	0.29	0.08
Export	0.0	3.4	0.0	3.4

SOURCES: The Alberta Research Council and the Canadian Energy Research Institute.

^aInterregional trade within Canada is maximized; exports to the U.S. are restricted.

^bBillions of undiscounted \$1988 Cdn.

^cBillions \$1988 Cdn. discounted at 5 percent.

occur other than the long-standing Hydro-Quebec and Newfoundland sale, together with those contracts which have already been signed between utilities in Canada and the United States. As no incremental trade is assumed either domestically or for the export market, the Net Present Value (NPV) of trade savings is zero. As shown in Table 5.9, the total capital and operating cost of meeting forecast peak and energy demand in Canada and the United States, assuming no incremental growth in electricity trade, is represented by the objective function value of \$1619 billion (\$1988 Cdn.).

Case 2 assumes full interregional integration in electric power planning. No non-economic constraints are imposed and generating and transmission capacity are added when and where economically desirable. This scenario results in an objective function of \$1593 billion (\$1988 Cdn.) for a savings in the total cost of generation and transmission required in Canada and the United States relative to the base case of \$26 billion (\$1988 Cdn.). Therefore, full integration results in a *significant* reduction in the total cost of new generating capacity and significant revenues for Canadian electric utilities. As most of the displaced generation would be fossil-fuelled, this scenario indicates that full integration or unrestricted trade would result in a significant reduction in environmental emissions, much of which would fall on eastern Canada owing to prevailing wind patterns.

Relative to the "No New Trade" scenario, the NPV value for trade savings totals \$3.5 billion (\$1988 discounted Cdn.); inter-utility trade within Canada accounts for \$130 million or only 4 percent of these savings. Electricity trade between Quebec and Ontario accounts for the lion's share of the Canadian trade component (82 percent); trade between Manitoba-Ontario accounts for the residual.

Case 3 assumes a situation where interregional trade within Canada is maximized but electricity exports to the United States are restricted. As shown in Table 5.9, the objective function falls to \$1616 billion, indicating a total savings of some \$3 billion (\$1988 Cdn.) accruing from greater Canadian interprovincial electricity trade relative to the "No New Trade" or the "business as usual" case. The NPV of Canadian trade savings increases from \$130 to \$290 million (\$1988 discounted Cdn.) with Quebec - Ontario trade accounting for 89 percent of this total.³³ Total discounted revenues from exports, however, fall significantly relative to the Case 2 trade scenario.

As there is some uncertainty associated with the future mix of coal and nuclear powered generation within Ontario, the last case

shown in Table 5.9 assumes that all *new* generating capacity brought on stream in Ontario is nuclear. All the other scenarios depicted in Table 5.9 assume a 50/50 split in the construction of new coal and nuclear plants. Unrestricted trade between all regions is also assumed in this scenario. Aside from the NPV of trade savings, this case is very similar to the full trade scenario depicted in Case 2. Ontario purchases less electrical power from Hydro-Quebec owing to a greater reliance on nuclear, and the United States purchases slightly more hydro power than in Case 2. Figure 5.6 compares the NPV of trade savings for Canadian interties and exports to the United States for the various scenarios.

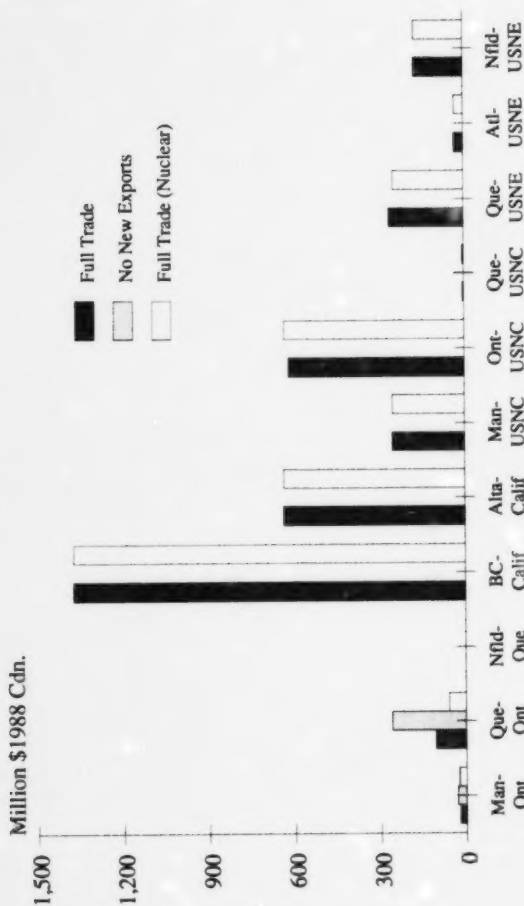
The potential savings in capital and operating costs for new electrical generation through increased electricity trade are significant. However, as noted earlier, political, technical and environmental concerns would likely limit the full development of these savings.

Nevertheless, it is fair to say that greater electricity trade between utilities within Canada and between Canada and the United States would result in a reduction in the costs required to meet electricity demand. As a result, electricity rates would be somewhat lower. As the majority of the electrical generating capacity that would be displaced would be fossil-fuel fired, sizeable *environmental* benefits could also accrue from greater trade. On balance, these issues deserve the attention of utilities, regulators and the Canadian public.

While the benefits of greater integration seem obvious, little serious work has been done in Canada to date to bring about these efficiencies. For example, in the mid-1960s, the concept of a National Power Network in Canada consisting of transmission interconnections between the power systems of the ten provinces was evaluated. It concluded that the interconnection and coordinated development of the power systems of all of the provinces could be beneficial and that further studies should be undertaken to evaluate the feasibility of interconnection and coordinated development. The concept of a Western Grid which would allow for greater wheeling of power through the Western provinces has also been raised on numerous occasions.

More recently, the Energy Options Advisory Committee, in its report Energy and Canadians-Into the 21st Century, spoke to the benefits to be gained through interprovincial trade and cooperation in Canada's electric power development.³⁴

Figure 5.6
NPV of Trade Savings
Interiors and Exports



SOURCES: Alberta Research Council and
Canadian Energy Research Institute.

In September 1988, the federal energy minister asked the National Energy Board to report on possible measures that could be taken to:

- enhance interprovincial trade in electricity;
- encourage greater cooperation between utilities in systems planning and development; and
- enable buyers and sellers of electricity to obtain commercial access to available transmission capacity through intervening provinces for wheeling purposes.

The National Energy Board is expected to shortly announce the procedure it will be following to examine these issues.³⁵

5.6 Conclusions

The economic benefits resulting from greater electricity trade and coordination in electric power planning lie largely in the economies of scale and the advantages of diversity in load, risks and operating costs available to the trading utilities.³⁶ Investment costs are reduced through the use of larger generating units, which cost less to build per unit of output, and through the lower reserve margins which result from reducing the ratio of generating unit size to combined system peak load. Operating economies are gained through the load diversity of the combined systems, reduced operating costs per unit of output of larger units, and more complete use of the lowest cost generation option available to the systems. Additional savings are possible through coordination of construction programs so as to minimize the costs of temporary excess capacity resulting from the addition of generation in stepwise blocks. Reliability benefits may be realized as either a reduction in reserves required to achieve a given level of reliability, or as an increase in the level of reliability of the coordinated systems.

The savings which can accrue from electricity trade and more coordinated planning in electric power systems can be substantial. For example, a recent evaluation of benefits in the United States showed total national savings to consumers in excess of \$15 billion per year in the last few years due to inter-utility coordination and power pooling. About three-quarters of these savings came in the form of capital savings and about one-quarter from fuel cost reductions. If not for the interconnections between utilities and the intercompany coordination presently practiced, about 14 percent more generating capacity would have been required than actually existed to maintain

adequate reliability. By the mid-1990s, this saving in generating capacity is expected to be about 20 percent.³⁷

As shown by the ELGEM model results, greater integration in power planning within Canada and between Canada and the United States could potentially produce savings as high as \$26 billion (\$1988 Cdn.). The savings to greater integration within Canada alone could be in the order of \$3 billion. It is worth noting that the benefits to electricity trade suggested by our model represent only the most economic means of planning generation and transmission to meet forecast electrical growth. A trade attribute and significant policy consideration not accounted for in our analysis is maintaining security of supply through the encouragement of a diversity of supply sources. For completeness, an assessment of the benefits of greater interregional trade should also consider the differential impact on regional environmental emissions.³⁸ An assessment of the technical constraints in interconnecting electrical systems and ensuring reliable operations is also a factor which must be weighed in the evaluation of greater trade and systems coordination.

In short, there are numerous questions and perspectives which must be incorporated in definitively concluding whether greater integration will result in a net benefit to the individual parties involved in electricity trade. While the incorporation of these and various other constraints could act to reduce the lifetime benefits of trade, the overriding benefits of greater coordination of generation and transmission resources clearly points to the evaluation of greater integration in electric power planning. As such, the planning environment of electric utilities and their regulators must be expanded to encompass a broader focus and appreciation of what constitutes least-cost power planning. If least-cost planning is to account for the true risk-adjusted cost of alternative sources of supply, as argued by proponents of conservation, demand-side management and independent power production, then the potential to be derived by power purchases should also be included in the basket of supply options under consideration.

While the Canadian electric utility industry is well positioned to evaluate all the options which would serve to reduce costs and which afford the necessary system flexibility and reliability, political jurisdiction in many respects counters the potential for greater energy efficiency. It seems important in this regard that a fundamental evaluation of provincial public policy across Canada be undertaken. *Equally* important is the need to educate the Canadian public on the benefits to the environment of greater electricity trade and

coordination in electric power planning. Canada's Free Trade Agreement with the United States, the First Ministers' (August 1989) commitment to examine resolution of interprovincial trade barriers, and studies underway by TransAlta Utilities and B.C. Hydro are positive steps forward in resolving these inefficiencies.

The complexity of the regulatory issues that must be addressed poses formidable constraints to liberalized trading relations and greater systems coordination in power planning, but technical and environmental issues may rule the day. The public's concern with the aesthetic and potential health affects of high-voltage transmission lines and political considerations constitute important barriers to greater coordination. A fundamental examination of the costs and benefits of greater coordination within the context of least-cost, risk-adjusted utility planning is warranted. An important and necessary corollary of this is a better public understanding of the benefits of greater electricity trade and its potential role in reducing emissions which are harmful to Canada's environment.

Footnotes

¹See Volume II for a detailed description of the historical development of Canadian electric power and the importance of electricity exports.

²Energy, Mines and Resources, Electrical Power In Canada 1988, (Ottawa: Minister of Supply and Services Canada, 1989), p. 55.

³Ibid., p. 53.

⁴Dina Washburn Kruger, Plugging Into Canada: Prospects for U.S.-Canadian Electricity Trade (Washington, D.C.: Investor Responsibility Research Center, 1988), p. 1.

"The economic landscape in the years since Congress passed the Clean air Act has favoured keeping existing plants on line and avoiding building new ones. This was driven partly by the costs of pollution control on new plants but more directly by unusually high interest rates of the 1970s, coupled with declining and unpredictable load growth. Power plant life-extension and geriatric programs have become a major focus of savvy utilities, and some experts believe that it may be possible to keep old plants in service almost indefinitely. Under the Clean Air Act, if the cost of a life-extension program exceeds 50 percent of a "comparable new facility," the plant may be subject to New Source Performance Standards (NSPS). According to the Electric Power Research Institute: "This regulation has not yet been tested, and utilities are unsure whether the 50 percent trigger refers only to a one-time capital expenditure or to aggregated refurbishment costs over several year."

The status quo offers a strong incentive for utilities to keep the oldest, and often dirtiest, plants on line as long as possible. In extending the life of existing plants, the utility avoids siting disputes, heavy capital requirements, prudence reviews, and major disallowances (see U.S. Congress, Office of Technology Assessment, Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition, OTA-E-490 (Washington, D.C.: U.S. Government Printing Office, May 1989), pp. 219-220).

⁵Dina Washburn Kruger, Plugging Into Canada: Prospects for U.S.-Canadian Electricity Trade, p. 51.

⁶Ibid., p. 1.

⁷Ibid., p. 12.

⁸Ibid., p. 13.

⁹Ibid., pp. 13-14.

¹⁰Ibid., pp. 14-17.

¹¹Ibid., p. 65.

¹²Energy, Mines and Resources Canada, Electrical Power In Canada 1988, p. 72. It is interesting to note that the forecasts presented in EPIC 1987 were 34, 50 and 56 TW.h for utilities, the NEB and EMR, respectively.

¹³Ontario Select Committee on Energy, Report on Ontario Hydro Draft Demand/Supply Planning Strategy, vol. I, 1st Session, Thirty Fourth Parliament (Toronto: Legislative Research Service, January 1989), p. iv.

¹⁴B.C. Hydro/Alberta Interconnected System, Generation Coordination Study (Calgary: TransAlta Utilities, March 22, 1989), p. 3.

¹⁵U.S. Department of Energy, Office of Policy, Planning and Analysis, Northern Lights: The Economic and Practical Potential of Imported Power from Canada (Washington, D.C.: U.S. Department of Energy, December 1987), p. H-1.

¹⁶Ibid, p. H-2.

¹⁷Electric Power Research Institute, Technical Limits to Transmission System Operation, EPRI EL-5859, Final Report, prepared by Power Technologies, Inc. (Palo Alto, California: Electric Power Research Institute, June 1988), pp. 1-2.

¹⁸Dina Washburn Kruger, Plugging Into Canada: Prospects for U.S.-Canadian Electricity Trade, p. 55.

¹⁹Michael R. Gent, Electricity Supply and Demand: An Overview, proceedings from American Power Conference, volume 49, 1987, p. 16.

²⁰U.S. Department of Energy, Office of Policy, Planning and Analysis, Northern Lights: The Economic and Practical Potential of Imported Power from Canada, p. H-6.

²¹Dina Washburn Kruger, Plugging Into Canada: Prospects for U.S.-Canadian Electricity Trade, p. 38. For a comprehensive description of power frequency fields and public health, see U.S. Congress, Office of Technology Assessment, Biological Effects of Power Frequency and Magnetic Fields - Background Paper, OTA-BP-E-53 (Washington, D.C.: U.S. Government Printing Office, May 1989).

"The research results to date are complex and inconclusive. Many experiments have found no difference in biological systems that have been exposed to fields and those that have not. It still is not possible to

demonstrate that such risks exist, and they may not. However, the emerging evidence no longer allows one to conclude that there are no risks." [See U.S. Congress, Office of Technology Assessment, Electric Power Wheeling and Dealing: Technological Consideration for Increasing Competition, OTA-E-409 (Washington, D.C.: U.S. Government Printing Office, May 1989, p. 26)].

See also OTA, Chapter 7, "Siting, Environmental, and Health Issues Associated with Increased Competition and Expanded Transmission Assess."

22"... Furthermore, little attention has been given to field exposures that result from sources other than high-voltage transmission lines. As noted earlier, fields from distribution lines, building wiring, and appliances could be primary sources of public health effects. It will be important for legislators, regulators, and others to address the issue as one of field exposure rather than as a problem of high-voltage transmission lines. Otherwise, enormous attention may be devoted to one, possibly minor, source of public exposure while ignoring other, possibly major, sources of public exposure." See U.S. Congress, Office of Technology Assessment, Electric Power Wheeling and Dealing: Technological Consideration for Increasing Competition, p. 241.

23Dina Washburn Kruger, Plugging Into Canada: Prospects for U.S.-Canadian Electricity Trade, p. 42.

24Alberta Energy Resources Conservation Board, 240-kV Transmission Line 946/947L Ellerslie-East Edmonton (Calgary, Alberta: Energy Resources Conservation Board, May 1989), p. 15.

25United States General Accounting Office, Canadian Imports: A Growing Source of U.S. Supply, GAO/RCED-86-119 (Washington, D.C.: United States Capital Accounting Office, April 1987), p. 34.

26U.S. Department of Energy, Office of Policy, Planning and Analysis, Northern Lights: The Economic and Practical Potential of Imported Power from Canada, pp. 3-5.

27Henry Lee, Norman Foster and Edward Parson, Canadian Electricity Imports: An Assessment of the National Security, Economic and Environmental Implications, E-88-06 (Harvard University: April 1988), pp. 75-77.

28National Energy Board, The Regulation of Electricity Exports (Ottawa, Ontario: Minister of Supply and Services, June 1987), p. 40.

29Ibid., p. 42.

30Ibid., p. 43

³¹Ibid., pp. 44-45.

³²The complete results of the scenarios are discussed in Volume II.

³³In further support of the benefits of enhanced Canadian interregional electricity trade, a recent study by Rogers and Rowse concluded:

- Complete interregional cooperation leads to substantial savings (\$10.3 billion \$Cdn. 1990) in absolute terms but a small gain in percentage terms over self-sufficiency. Because some regions have attractive generation alternatives and constructing transmission lines is costly, there is sufficient diversity only between certain regions to make interregional linkage compelling. [See J. Scott Rogers and John G. Rowse, Canadian Interregional Electricity Trade: Analyzing the Gains from System Integration During 1990-2020, Discussion Paper 116 (Calgary, Alberta: University of Calgary, Department of Economics, March 1989), p. 2.]

³⁴Energy Options Advisory Committee, Energy and Canadians: Into the 21st Century. A Report on the Energy Options Process (Ottawa: Ministry of Supply and Services, 1988), p. 20-30.

The Advisory Committee recommended that the federal government take a leadership role:

- by examining and clarifying the conditions under which one province has a right to access, on a business basis, the electrical grid or corridor of another province and the rules under which one province is able to purchase electricity from another province on a non-discriminatory basis;
- by assisting the resolution on a business basis of a number of contentious issues, including the Churchill Falls issue, not simply as a mediator but as a principal participant in future developments; and
- by reorienting federal regional development initiatives to encourage greater interprovincial cooperation and efficiency in energy matters.

³⁵J. G. Fredette, How Ontario's Energy Choices Have Been Affected By the National Energy Board, presentation to Ontario's Energy Choices Conference, Toronto, Ontario, April 3, 1989, p. 16.

³⁶Federal Energy Regulatory Commission, Office of Electric Power Regulation, Power Pooling In the United States, FERC-0049 (Washington, D.C.: Federal Energy Regulatory Commission, 1981), p. 15.

³⁷John Casazza, "Free Market Electricity: Potential Impacts on Utility Pooling and Coordination," Public Utilities Fortnightly, vol. 121, no. 4, February 18, 1988, p. 17.

³⁸The Canadian Energy Research Institute is undertaking a study of regional environmental emissions resulting from future electric power development.

Chapter 6

ELECTRICITY AND THE ENVIRONMENT

6.1 Introduction

The production of electric power, regardless of the source--non-conventional (wind, solar, tidal, etc.) as well as conventional (nuclear, fossil fuel and hydro)--has potentially adverse effects on the environment. These adverse effects arise at each stage of the fuel cycle as well as in the transmission of electricity.¹

At the fuel production (or extraction) stage, for example, the mining of coal and uranium and the production of natural gas can disturb large areas of land, and in some cases diminish productivity of land use for agriculture, forestry and recreation. In the production of hydro power, large tracts of land are alienated from other potential uses and entire ecosystems disrupted by large-scale flooding. Similarly, commercial development of less conventional forms of energy, such as wind and solar, which are relatively land intensive in nature, may end up placing large strains on the environment.

At the fuel processing or refining stage--which applies to most fossil fuels--environmental impacts take the form of solid, liquid and gaseous "wastes" or emissions. The refining and manufacturing of nuclear fuels results in the creation of small volumes of extremely toxic and radioactive wastes. The processing of natural gas and the refining of petroleum is responsible for significant emissions of sulphur oxides, nitrogen oxides and hydrocarbons.²

The energy transportation or delivery stage also has environmental impacts. The recent oil spill from the Exxon Valdez off the coast of Alaska has served to focus Canadian attention on this stage of the energy cycle. Similarly, the transportation of liquefied natural gas (LNG) imposes risks to safety, while oil and gas pipelines are also subject to risk of accidental rupture and the associated impacts on the environment. In addition, as noted in Chapter 5, the public's perception of the detrimental impacts of electromagnetic radiation on human health is becoming an increasing concern in the context of the transmission of electric power.³

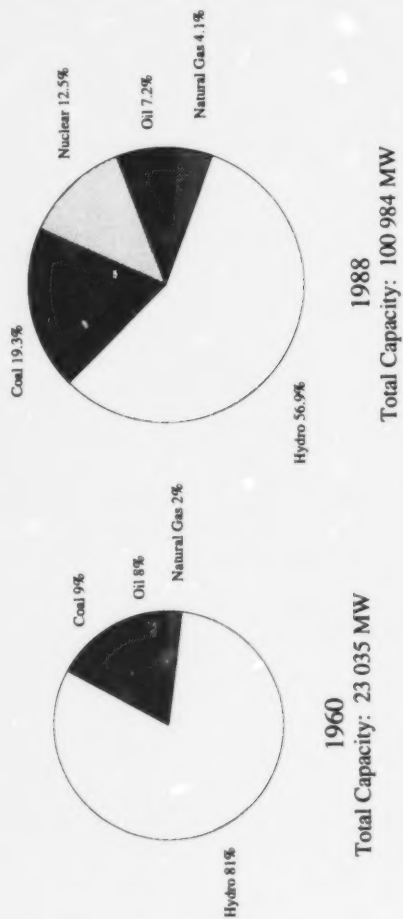
Nuclear power production currently accounts for only 16 percent of total Canadian electricity requirements.⁴ Questions regarding the safety of operation for nuclear reactors, as well as the disposal of high level nuclear wastes, have become a major source of environmental concern to Canadians, particularly in the province of Ontario.

Despite all of these effects, however, the greatest single source of public concern in Canada over the environmental effects of energy use and production relates to the combustion of fossil fuels. The combustion of fossil fuels, which accounts for about 22 percent of total Canadian electricity production⁵ and constitutes the second most important source of generation in Canada (see Figure 6.1), gives rise to significant atmospheric emissions of sulphur dioxide, nitrogen oxides and carbon dioxide. Growing awareness of the role of these atmospheric emissions in causing acid rain, global warming⁶ and a deterioration of local air quality has centred the public's attention on this stage of the energy cycle (see Table 6.1). Numerous conferences, publications and news articles have heightened public awareness of economy-energy-environment linkages, the Brundtland Commission Report, *Our Common Future*, being one of the most noteworthy to raise the issue of "sustainable development." The essence of sustainable development is that economic development and protection of the environment can be mutually reinforcing, not mutually exclusive. The environment has consequently come centre-stage and is the cornerstone of increased interest in means which will improve the efficiency of electricity production and end-use and thereby, reduce harmful emissions.

A large number of regulations, standards and guidelines currently exist in Canada relating to different activities in the electrical sector and their impact on the environment. Regulations established over the last 15 years in Canada govern the siting, construction, maintenance and operation of hydro and fossil fuel-fired facilities and nuclear power stations. These regulations will continue to influence the development of new generation facilities. There are several reasons, however, why emerging standards and regulations governing the emission of atmospheric pollutants such as SO₂, NO_x, VOCs and possibly CO₂, will dominate the environmental agenda over the coming decade.

First and foremost is the fact that recent Canadian agreements to limit atmospheric emissions under the SO₂ (1985) and NO_x (1988) Protocols will become increasingly binding on Canadian utilities

Figure 6.1
Installed Generating Capacity
by Fuel Type



SOURCE: EMR Canada, Electric Power
in Canada, 1988.

TABLE 6.1
SOURCES AND IMPACTS OF
ENVIRONMENTAL PROBLEMS

Problem	Impact	Principal Source
Acid Rain	Acidification of lakes, streams, groundwater and soil. Reduces growth of forests and threatens fish and other wildlife. ^a	Sulphur Dioxide (SO ₂) and Nitrogen Oxides (NO _x)
Ground Level Ozone (Urban Smog)	Results in respiratory and other health problems in humans and injures trees, crops and other vegetation.	Nitrogen Oxides (NO _x) and Volatile Organic Compounds (VOCs)
Global Warming	Increased global temperature and weather instability, economic and political disruption.	Carbon Dioxide (CO ₂), Methane (CH ₄), Chlorofluorocarbons (CFCs), Nitrogen Oxides (NO _x) and Ozone (O ₃)

SOURCE: Energy, Mines and Resources Canada, Policy Studies Group, 1989.

^aMore pronounced in Central Canada due to lack of buffering ability of soils to neutralize acid rain together with the absolute level of acid gas emissions.

over the next 10 to 15 years. Furthermore, public pressure is being exerted on various levels of government to initiate actions to control emissions of greenhouse gases, particularly CO₂. This is the result of growing public awareness and concern over the possible environmental implications of the global warming phenomenon.

Just as important, however, is the fact that fossil-fired generation currently dominates electricity generation in a number of Canadian provinces (outside of Quebec, Newfoundland, Manitoba, British Columbia, and the Yukon Territories) and that several Canadian utilities are planning significant additions to coal-fired generating capacity over the next 15 years. Emerging pressures to control environmentally hazardous emissions will impact not only on the operation and utilization of existing fossil-fuelled generating stations across Canada, but will also affect costs and thereby the choice of technology and Canada's future generation mix. This suggests that the regulation of atmospheric emissions will emerge in the 1990s as the dominant environmental issue facing the Canadian electrical sector.

6.2 Atmospheric Emissions

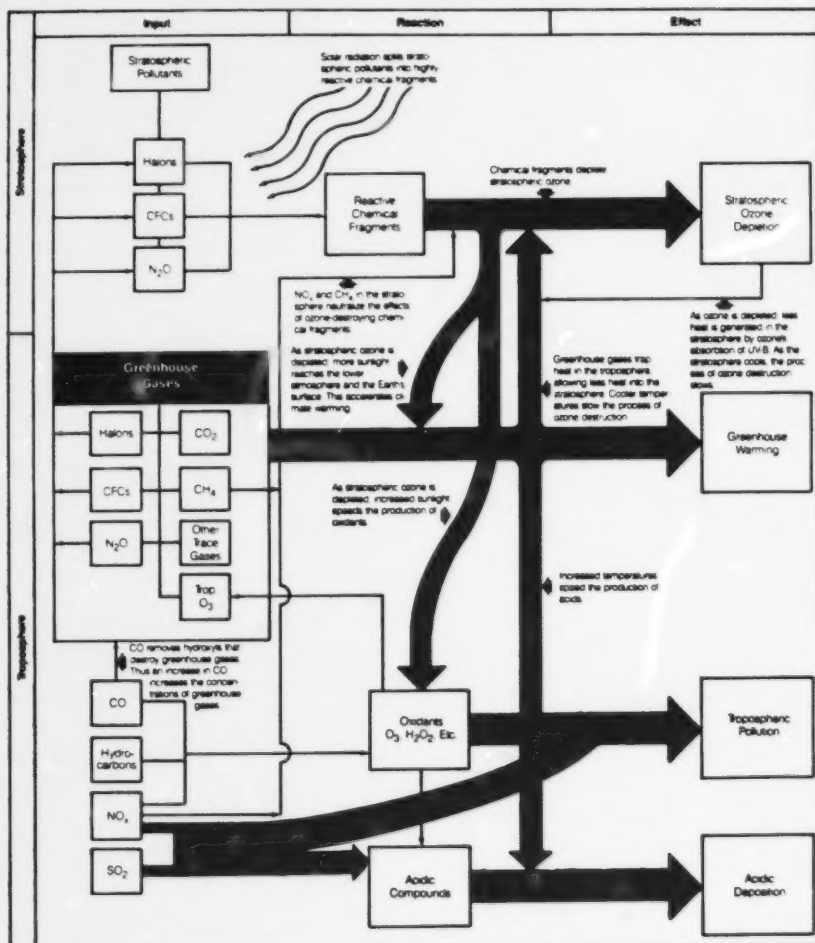
Recent public opinion polls suggest that environmental issues are beginning to rival unemployment, inflation and the deficit as the greatest source of concern to Canadians in this decade.⁷ This concern, and much of the associated response by governments in Canada and around the world, is focussed to a large extent on atmospheric pollution. In this context, a number of clearly distinguishable sources of concern have been identified, including acid rain, ground level ozone (urban smog) and global warming--the "greenhouse effect" (see Figure 6.2). Each of these issues is associated with emissions of sulphur dioxide (SO₂), nitrogen oxides (NO_x), VOCs (volatile organic compounds) and carbon dioxide (CO₂). An important source of these emissions, in Canada and throughout the world, is the burning of fossil fuels in electric power plants.

6.2.1 Acid Rain

"Acid rain is the greatest environmental threat that Canada has ever faced."⁸ This perception is reflected in widespread public and political support for the introduction of measures to control acid gas emissions, such as the Canadian Acid Rain Control Program initiated in 1985.

Emissions of SO₂⁹ and NO_x¹⁰ produced primarily by non-ferrous smelting and the burning of fossil fuels are believed to be

Figure 6.2
Interactions of Atmospheric Pollutants



Source: Compiled by World Resources 1988-89

Key

CFCs — chlorofluorocarbons

N_2O — nitrous oxide

CH_4 — methane

CO_2 — carbon dioxide

Trop. O_3 — tropospheric ozone (a pollutant, as opposed to stratospheric ozone, which is beneficial)

CO — carbon monoxide

NO_x — nitrogen oxides (NO and NO_2)

SO_2 — sulfur dioxide

H_2O_2 — hydrogen peroxide

UV-B — ultraviolet B radiation

primary contributors to the production of acid rain. In the atmosphere, these two forms of "acid gas" can be transformed into sulphuric and nitric acids¹¹ which, in turn, are often carried long distances by prevailing winds before falling as acid rain, snow, dust or fog. All of these wet and dry forms of acid precipitation are commonly referred to as acid rain, or more generally, as acid deposition (see Figure 6.2).

Acid rain is a "regional" problem as distinct from a global one. Because of the nature of wind patterns in North America, a major source of acid rain in Canada is emissions of SO_2 and NO_x in the United States. On the other hand, Canadian emissions of these two gases also contribute to acid rain in the United States.¹² For decades, acid rain has been recognized as a potentially serious long-term air pollution problem for industrialized countries. Acid deposition increases the acidity of lakes, streams, ground water, and soil, threatening wildlife populations and reducing growth in forests as well as agricultural products. In addition, acid rain erodes buildings and materials and is suspected of contributing to respiratory problems in humans.¹³

From an economic perspective, acid rain reduces the productivity and value of natural resources in various sectors of the economy, including fishing, forestry, tourism and agriculture. The damage caused by acid rain to these sectors each year is estimated to exceed \$1 billion. These effects are most severely felt in Eastern Canada, where an area as large as 2.6 million kilometres is affected.¹⁴ The resource base at risk in this area alone, sustains approximately 80 percent of Canada's real gross domestic product.

6.2.2 Ground Level Ozone

Ozone (O_3), often referred to as photochemical or urban smog, is produced in the lower atmosphere from photochemical reactions involving nitrogen oxides and VOCs. Man-made emissions of NO_x and VOCs, primarily from the combustion of fossil fuels, as well as certain industrial and commercial processes, have elevated ozone levels in many parts of the country, causing potentially serious health problems. Indeed, more than 25 years after the passing of the Canadian Clean Air Act, over half of the Canadian population is regularly exposed to ground level concentrations of ozone which are known to have adverse health effects (see Tables 6.2 and 6.3). "The principal sources of current and future NO_x emissions in Canada are motor vehicles, off-road diesels, natural gas production and power plants; the

TABLE 6.2
PRELIMINARY OZONE LEVELS IN
SELECTED URBAN AREAS
(1988)

City	Maximum 1 hr. Level ($\mu\text{g}/\text{m}^3$) ^a	Number of Hours Greater Than 160 $\mu\text{g}/\text{m}^3$ ^b	Number of Hours Greater Than 300 $\mu\text{g}/\text{m}^3$
Vancouver ^c	205-415	9-32	0-4
Edmonton	160	0	0
Calgary	175	1	0
Regina	130	0	0
Winnipeg	180	1	0
Toronto ^c	310-360	92-138	0-3
Sudbury	220	78	0
Kitchener	230	137	0
Ottawa	250	55	0
Montreal ^c	255-350	23-153	0-17
Saint John ^d	195	31	0
Halifax	155	0	0

SOURCE: Federal/Provincial Long Range Transport of Air Pollutants Steering Committee, Development of a National Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOC) Management Plan for Canada: Executive Summary (Ottawa, Ontario: Environment Canada, July 1989), p. 8.

^aMicrograms per cubic metre.

^bMaximum acceptable level.

^cRanges refer to data from a number of sites within the metropolitan area.

^dData for May and June only.

TABLE 6.3
GUIDE TO THE NITROGEN CYCLE
KEY PLAYERS AND PROCESSES

Major Chemical Forms of Nitrogen		
Ammonia/ Ammonium	NH_3/NH_4	A major nutrient, ammonia is a gas and is highly soluble in water.
Nitrogen gas (molecular nitrogen)	N_2	Principal constituent of the atmosphere, unusable except by a few nitrogen-fixing bacteria and algae.
Nitrous oxide (laughing gas)	N_2O	Important role in ozone cycle and greenhouse effect, product of denitrifying bacteria.
Nitric oxide	NO NO_x	Combustion product, natural regulator of stratospheric ozone.
Nitrogen dioxide	NO_2	Formed by the reaction of NO with oxygen in the air, NO_2 is an urban air pollutant, a precursor of acidic deposition, and aids the formation of tropospheric ozone.
Nitrite ion	NO_2^-	Intermediate product in the conversion of ammonia to nitrate
Nitrate ion	NO_3^-	Principal nutrient form, component of acid rain, contributes to methemoglobinemia

SOURCE: World Resources Institute and International Institute for Environment and Development, *World Resources 1988-89* (New York, New York: Basic Books, Inc., 1988), p. 183.

principal sources of current and future VOC emissions in Canada are gasoline-powered motor vehicles, the gasoline fuel cycle from production to vehicle refuelling, refineries and petrochemical plants, application of surface coatings and solvent use."¹⁵

Public concern over this form of air pollution has heightened over the last few years, due partly to the fact that record-breaking levels of ozone have been detected in several North American cities over the summer months,¹⁶ and partly as a result of increasing evidence linking periods of elevated ozone to serious human health problems. Also, increased awareness of the regional nature of this issue--VOCs and NO_x from the central United States, for example, are a significant cause of elevated ozone levels in Southern Ontario and Quebec--has drawn attention to this problem.

Evidence of the economic implications of elevated ozone levels in Canadian cities has occurred at two different levels. First and foremost, increased ozone concentrations have been linked in a number of studies to increased respiratory problems in humans and increased health costs. In cases of severe reaction to elevated ozone levels, usually involving the aged and asthmatic, lengthy periods of hospitalization have occurred, with the result that significant amounts of scarce health care resources have been diverted from other areas of patient care.

In response to particularly serious incidents of elevated ozone, such as occurred in the city of Toronto in the summer of 1988, the possibility of having to restrict transportation and manufacturing activities arises. In this context, the potential costs associated with lost manufacturing output and serious travel inconvenience are considerable.

Ozone injures plant tissues, inhibits photosynthesis and increases the susceptibility of crops to other pollutants, disease and drought. "The total commercial value of ozone sensitive crops grown in areas where ozone levels exceed the damages threshold is estimated at more than \$2 billion; forest resources potentially at risk are estimated at several billion dollars."¹⁷

6.2.3 The Greenhouse Effect and Global Warming

When gases--mainly water vapour, carbon dioxide, methane, nitrous oxide, chlorofluorocarbons (CFCs) and ozone--build up beyond the world atmosphere's capability to sequester them, the so-called

"greenhouse effect" occurs (see Figure 6.2). The build up of these gases increases the amount of heat trapped by the greenhouse "blanket," contributing to an increase in the earth's surface temperature and a potentially drastic altering of global climate patterns. While uncertainties surround the extent and timing of the global warming effect that will be produced by the buildup of greenhouse gases, a large part of the scientific community is convinced that the greenhouse effect poses the greatest environmental threat in human history.

The buildup in greenhouse gases which has occurred over the last century is believed to be explained, almost exclusively, in terms of human activities. It is the growth in such activities as fossil fuel combustion, deforestation, agricultural extension and intensification as well as certain industrial activities (such as refrigeration and the cleaning of microchips) which in turn has resulted in increasing concentrations of the principal greenhouse gases in the atmosphere (see Table 6.4).¹⁸ The increasing concentration of carbon dioxide, which contributes to roughly 50 percent of the greenhouse effect, has been well established. Atmospheric carbon dioxide concentrations have increased roughly 10 percent over the last 30 years. However, man-made emissions of CO₂, resulting primarily from the combustion of fossil fuels, have more than doubled over this same period. These emissions are expected to play a greater role in accelerating global climate change in the next 50 years.

Although CO₂ is the most important greenhouse gas that humans can control, it is not the only one. Atmospheric concentrations of the other infrared-absorbing gases (water vapour, carbon dioxide (CO₂), ozone (O₃), methane (CH₄), nitrous oxide (N₂O), and CFCs) are also increasing, and they can add significantly to the greenhouse effect, bringing much closer the time when the radiative equivalent of CO₂ doubling might be expected to occur. We estimate that CH₄, N₂O and the CFCs together are currently contributing nearly as much to the annual change in the earth's radiation balance as CO₂ does. ... Important sources of N₂O apparently include tropical and subtropical forests, soils, oxidation of the nitrogen contained in fossil fuels (mainly coal), and, to a lesser degree, oxidation and/or reduction of nitrogen in agricultural fertilizers. Many of these sources of CH₄ and N₂O are related to or influenced by human activities.¹⁹

Table 6.4 lists the concentrations of the gases, their greenhouse efficiency per molecule relative to carbon dioxide, and their approximate atmospheric residence times. The CFCs result

TABLE 6.4
MAJOR GREENHOUSE GASES AND THEIR CHARACTERISTICS

Gas	Atmospheric Concentration (ppm)	Annual Increase (%)	Life Span (yrs.)	Relative Greenhouse Efficiency (CO ₂ =1)	Current Greenhouse Contribution (%)	Principal Sources of Gas
Carbon Dioxide (Fossil Fuels)	351.3	0.4	x ^a	1	57 (44)	Coal, Oil, Natural Gas,
(Biological)					(13)	Deforestation
Chlorofluoro- carbons	.000225	5	75-111	15,000	25	Foams, Aerosols, Refrigerants, Solvents
Methane	1.675	1	11	25	12	Wetlands, Rice, Fossil Fuels, Livestock
Nitrous Oxide	.31	0.2	150	230	6	Fossil Fuels, Fertilizers, Deforestation

SOURCE: Christopher Flavin, *Slowing Global Warming: A Worldwide Strategy* (Washington, D.C.: The Worldwatch Institute, 1989), p. 13.

^aCarbon dioxide is a stable molecule with a 2-4 year average residence time in the atmosphere.

exclusively from human activities. The other greenhouse gases are emitted both from natural sources and through human activities such as fuel combustion. Tropospheric ozone is formed through complex interactions of other products of combustion. Once emitted, many of the gases persist for very long periods of time. This is especially true of the CFCs. Thus, even reducing emissions to zero will not immediately reduce the effects of climate change.

The exact timing and magnitude of possible changes in global climate conditions which may occur as a result of increased concentrations of greenhouse gases in the atmosphere is subject to considerable uncertainty. Nonetheless, what is clear is that within the range of estimates of global warming currently supported by a large portion of the scientific community, the possible economic and social implications of the greenhouse effect are staggering.

At a two-stage workshop in Villach (Austria) and Bellagio (Italy),²⁰ a group of over 400 scientists from around the world examined how climate change resulting from increasing concentrations of greenhouse gases could affect the environment and society during the coming century. Several scenarios of climate change were developed.

Under the "upper bound" scenario, which assumes that no concerted effort is made to reduce emissions of greenhouse gases, global surface temperatures were predicted to increase by 0.8 degrees per decade, until the middle of the next century. The most extreme temperature increases would likely occur in the higher latitude of the Northern Hemisphere during the winter months, when the increase in temperature could be more than twice the global average.

As a result of these temperature changes, precipitation patterns could be changed dramatically, the severity and frequency of extreme weather disturbances would increase, and sea levels could rise by as much as 1.5 metres—creating havoc in coastal areas. While the political and social implications of these possible outcomes have yet to be determined, the potential economic impact, in terms of adjustments to land use and weather patterns, alone could be enormous.

The environmental and economic costs associated with acid rain, ground level ozone and global warming are, while not yet fully understood, potentially enormous. It follows that increasing pressures will be brought to bear on those sectors whose emissions contribute most significantly to these problems. This has potentially significant implications for all components of the Canadian energy sector,

including the electric industry, an important source of emissions of SO_2 , NO_x and CO_2 . For example, forecasts by Environment Canada for the electric utility sector indicate a doubling of nitrogen oxides and carbon dioxide emissions over the 1985-2005 period.

6.3 Recent Initiatives to Limit Atmospheric Emissions

Environmental quality is a shared responsibility of the federal and provincial governments in Canada. The provincial governments are responsible for intraprovincial environmental matters, while the federal government is responsible for environmental issues that are interprovincial or international in nature. In practice, this allocation of responsibility has meant that the Canadian government has the primary authority for regulating emissions from mobile sources, while the provinces retain the primary authority for controlling emissions from stationary sources such as electric power plants.

The environmental implications of such problems as acid rain and elevated ozone, as well as global warming, are interregional and international in nature. As a result, the federal government has come to play a large role in the establishment of initiatives designed to control a wide variety of atmospheric emissions, even where the source of pollution is primarily stationary in nature. International agreements entered into by the Canadian federal government will no doubt constitute the driving force behind provincial regulation of electric utility emissions of SO_2 , NO_x and CO_2 in Canada over the coming decade.

The first in a series of recent Canadian government initiatives to control emissions of SO_2 , NO_x and VOCs occurred in Geneva in 1979, when Canada became party to the United Nations Economic Commission for Europe (UNECE) Convention on Long Range Transboundary Air Pollution (LRTAP). The Convention, which was signed by over thirty industrial countries,²¹ recognized the possible adverse effects of air pollution and sought to encourage countries to reduce pollution, including transboundary pollution. While the Convention contained no specific measures to reduce atmospheric pollution, it succeeded in laying the foundation for future protocols which contain specific emission reduction targets for SO_2 and NO_x .

6.3.1 The SO_2 Protocol

In 1985, under the 1979 LRTAP Convention, Canada and other committing member countries joined in the signing of a SO_2

Protocol. The participants agreed to reduce their national annual sulphur emissions, or their transboundary fluxes, by at least 30 percent (from 1980 levels) by 1993. Furthermore, Canada and the other signatories to the Protocol agreed to examine the need for further reductions in SO_2 as environmental conditions might warrant.

In order to meet its obligations under the SO_2 Protocol, Canada put in place the Canadian Acid Rain Control Program. Under this Program, the core of which is made up of seven different federal/provincial agreements,²³ the provinces are to put in place measures to reduce total annual emissions of SO_2 from roughly 4.5 million tonnes in 1980 to 2.3 million tonnes in 1994. Regulatory and program measures to achieve more than 90 percent of the emission reduction targets required under the program are now in place and it is fully expected that the objectives of the program will be met (see Section 6.4 for information on the Program and its implications for Canadian utilities).

6.3.2 The NO_x Protocol

In 1988, the Canadian government signed a second Protocol to the 1979 LRTAP Convention directed towards achieving specific NO_x emission reduction targets. Canada and other signatories to the Protocol agreed to ensure that by 1995 their total emissions of NO_x , or their transboundary flows, would not exceed their 1987 levels. The countries involved also agreed to begin negotiating further measures, to commence in 1996, to control NO_x emissions at the level required to achieve "agreed upon environmental quality targets."

The federal government is currently in the process of establishing the various parameters of a Canadian NO_x/VOC Program.²³ This program will include, as is the case under the existing acid rain program, targets for total emissions in each province. These targets are currently the focus of discussions between the federal and provincial governments and major stakeholders. A specific plan of action will be presented to the Canadian Council of Ministers of the Environment (CCME) in 1990.

6.3.3 CO_2 Initiatives

As a result of increasing concern over the possible implications of the greenhouse effect, Canada's federal, provincial and territorial governments have recently taken several initiatives to evaluate the possible causes and consequences of global warming, as well as the associated policy implications.

In June 1988, Canada played host to a major international conference on global climate patterns--the Changing Atmosphere Conference. Recognition of building evidence that a direct linkage exists between atmospheric changes and increasing concentrations of "greenhouse" gases led to a conference recommendation that emissions of greenhouse gases worldwide be reduced by 20 percent from 1988 levels, by the year 2005.²⁴ In August 1988, the federal, provincial and territorial energy ministers established a task force to review energy related recommendations arising from the Changing Atmosphere Conference--particularly the recommendation that global carbon dioxide emissions be reduced by 20 percent of their 1988 level by the year 2005. The Task Force report was publicly released at the end of August 1989 and concluded that the measures which it examined would not be sufficient to attain the 20 percent target.²⁵

Specifically, the Task Force recommended:

1. Canada should continue to participate actively to develop a coordinated international response to climate change issues.
2. In light of the scientific uncertainties and the potentially significant changes in global climate which may occur, and the significant socioeconomic consequences of dealing with the greenhouse effect, a near-term program should concentrate on changes in energy and related policies, regulations and programs. The Task Force concluded that the most cost-effective means of reducing CO₂ emissions is through energy conservation and improved efficiency. In addition, electricity demand management programs must become a cornerstone of any strategy to reduce CO₂ over the short term.
3. That attention and effort be increased for:
 - economically and environmentally attractive and appropriate conservation and efficiency measures, renewable energy sources, and alternative fuel options;
 - R&D on efficiency of fossil fuel use (especially integrated coal gasification combined cycle), conservation, efficiency of energy use, renewable energy, alternative fuels;
 - substituting other energy sources for fossil fuels, especially for electricity generation including hydroelectricity and the nuclear option, both fission and ultimately fusion;

- examining sinks for CO₂ particularly if these have an economic base such as reforestation and enhanced oil recovery;
 - public education programs regarding the need for efficient use of energy and improved forestry and farming practice; and
 - setting an example of environmentally responsible energy use through government's own use of energy.
4. A comprehensive strategy must also include the following measures:
 - scientific research to refine our understanding of climate change;
 - plans for *adapting* to the significant changes which may occur no matter what measures are taken now to reduce greenhouse gas emissions;
 5. Individual provinces and territories should develop their own detailed inventories of CO₂ emissions and undertake studies of possible abatement technologies that may be appropriate for their jurisdiction.
 6. In considering actions to reduce greenhouse gas emissions, the Task Force strongly recommended:
 - that the scientific and technical communities within industry and governments be encouraged to ensure that technologies for reducing CO₂ emissions be consistent and technically compatible with technologies being developed to reduce other environmental effects (such as acid rain) of energy production and consumption.

It recommended that in light of the *global* nature of the problem, the *scientific uncertainties* related to global warming and of the need to conduct *regional* assessments of ways to reduce emissions and their impacts, it is prudent to continue to regard the recommendation of the Toronto Conference of a 20 percent reduction of 1988 CO₂ level by 2005 as an *illustrative target* rather than as a *formally* adopted goal.

The work of the Task Force is continuing as it reviews the scientific evidence for greenhouse gas concentration and effects, and investigates possible technical and policy approaches from a Canadian perspective. Canada will be following with great interest similar

studies on greenhouse warming which have been launched in the United States and elsewhere, as a direct result of the recommendations arising from the Changing Atmosphere Conference.²⁶

Canadian initiatives on CO₂ and climate change which are taking place within the international context include involvement in the Intergovernmental Panel on Climate Change (IPCC), established to consider issues related to global climate change and possible control of CO₂ emissions. The IPCC, which was established by the World Meteorological Organization and the United Nations Environment Program, held its first meeting in Geneva in November 1988. Delegates from more than thirty countries recognized global warming as *the most important environmental concern of our day* and one which requires immediate international action and coordinated response. The panel agreed that it is imperative to provide nations of the world with the best possible guidance on climate change issues within the shortest possible time frame, and gave itself 18 months in which to prepare its first report. To assist in this task, a variety of working groups have been formed to undertake detailed studies of environmental data, which may ultimately be used as the basis for evaluation of possible national and international responses.

6.3.4 Canada/U.S. Bilateral Agreements On Acid Rain

Initiatives to control emissions which contribute to regional acid rain problems have also been taken. In 1980, the U.S. and Canada signed a Memorandum of Intent to develop a bilateral agreement on transboundary air pollution, including SO₂ and NO_x emissions. While no concrete measures have yet emerged, interest in the pursuit of a bilateral agreement was rekindled recently when Prime Minister Brian Mulroney and President Ronald Reagan endorsed a Report of the Special Envoys.²⁷ The report called for a \$5 billion control technology demonstration program, ongoing bilateral consultations at the highest levels, and cooperative research projects. Currently, several acid rain/clean air control bills are under review by the United States Congress. While the timing and nature of acid rain legislation which will emerge is unclear, it is expected that the content of the acid rain control program adopted by the United States will have a significant bearing on any subsequent Canada/U.S. acid rain agreement.

6.3.5 The Significance of Target Reductions

Some indication of the significance of existing and proposed SO₂, NO_x, or CO₂ control targets may be obtained by examining the changes in the ratio of emissions to Gross Domestic Product (GDP) implied by these targets over time.

As Figure 6.3 indicates, SO₂ emissions,²⁸ which stood at 15 kilotonnes per billion dollars (\$1981 Cdn.) of GDP in 1980, are slated to decline under the Canadian Acid Rain Control Program to 5.4 kilotonnes per billion dollars by 1994. Indeed, much of this reduction has already occurred. As of 1987, SO₂ emissions stood at 10.5 kilotonnes per billion dollars of GDP. If the 1994 target level for total Canadian emissions of 2474 kilotonnes is maintained beyond 1994, as is expected to be the case, emissions of SO₂ per billion dollars of real GDP are expected to decline to 4.2 kilotonnes by the year 2005.

Under the NO_x Protocol, total Canadian emissions of NO_x will be frozen at their 1987 levels by 1994 and beyond. As indicated by Figure 6.4, this implies that NO_x emissions--in kilotonnes per billion dollars of real GDP--must decline from 5.1 in 1987 to 4.2 in 1994, and subsequently to 3.3 in 2005.

Finally, Figure 6.5 examines the implications of achieving a 20 percent reduction in total Canadian CO₂ emissions from current levels by the year 2005. As indicated, were such a target to be reached, emissions of CO₂ expressed in terms of kilotonnes per billion dollars (\$1981 Cdn.) of GDP would decline by roughly 50 percent--from 1197 in 1988 to 640 in 2005. These reductions imply some *very significant* changes in Canada's production and consumption of energy.

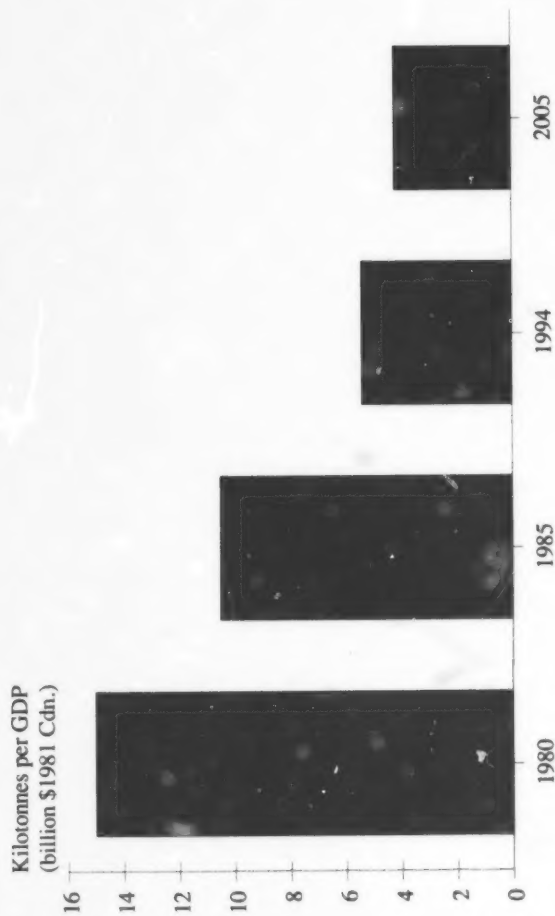
6.4 Pressures on the Canadian Electrical Sector to Reduce Acid Gas Emissions

As noted above, existing and proposed targets for atmospheric emission reductions will necessitate significant changes in the nature of energy consumption and production in Canada. In this section, the potential implications of meeting existing Canadian targets for the Canadian electrical sector are examined.

6.4.1 Trends in Canadian Acid Gas Emissions

Between 1970 and 1985, total Canadian emissions of SO₂ declined by almost 45 percent, with significant reductions occurring in

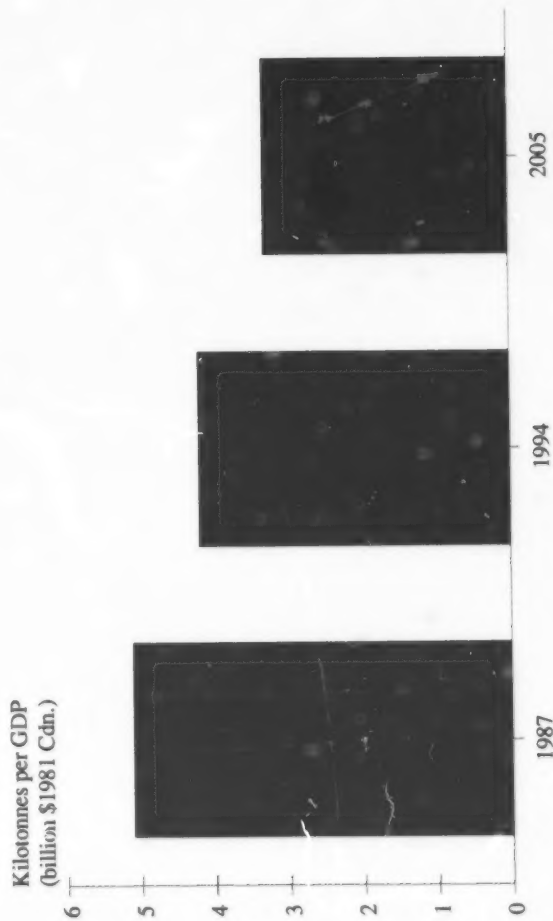
Figure 6.3
Canadian SO₂ Emissions Target



SOURCE: EMR Canada.

Note: GDP in \$1981 Cdn.

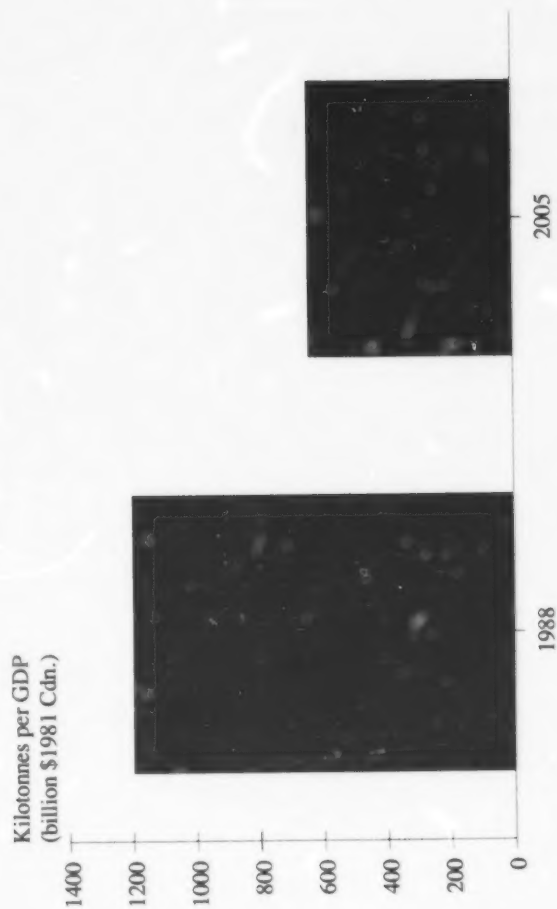
Figure 6.4
Canadian NOx Emissions Target



SOURCE: EMR Canada.

Note: GDP in \$1981 Cdn.

Figure 6.5
Canadian CO₂ Emissions Target



SOURCE: EMR Canada.

Note: GDP in \$1981 Cdn.

industrial processes and transportation, as well as non-utility fuel combustion. The only area where SO_2 emissions have not declined is in the Canadian electric utility industry. As indicated by Table 6.5, emissions from electric utilities have increased 47 percent, from 502 kilotonnes in 1970 to 736 kilotonnes in 1985. Moreover, the share of total emissions accounted for by the electrical sector has risen steadily over time, from 7.5 percent in 1970 to 20 percent in 1985.

The cause of increased SO_2 emissions in the Canadian electric industry is readily identified in Figure 6.6. Total electricity generation from fossil-fuelled plants increased from roughly 47 TW.h in 1970 to over 88 TW.h in 1985. In addition, SO_2 controls are just now being introduced by some Canadian utilities—Ontario Hydro has applied for approval to launch a sizable scrubber program and Sask-Power is installing emission reduction equipment at its Shand station.

Canadian NO_x emissions have also increased significantly. As shown in Table 6.6, total NO_x emissions increased from 1329 kilotonnes in 1970 to 1959 kilotonnes in 1985 (over 47 percent), while utility emissions increased from 149 kilotonnes to 236 kilotonnes (over 58 percent). It is important, however, to put these numbers in context. Transportation, including the off-road use of transportation-type engines, accounts for 64 percent, and fuel combustion by stationary utilities some 12 percent, of total current NO_x emissions (see Figure 6.7).

Some additional insight into the relative importance of Canada's electrical power sector to NO_x emissions is provided by estimates of the projected growth in NO_x emissions from 1985 to the year 2005 (see Table 6.5). As indicated, the single largest source of increased total emissions is the electrical sector—a doubling of emissions. As a result, the electrical sector's share of total Canadian emissions of NO_x , which stood at 12 percent in 1985, is forecast by Environment Canada to reach over 20 percent by 2005.

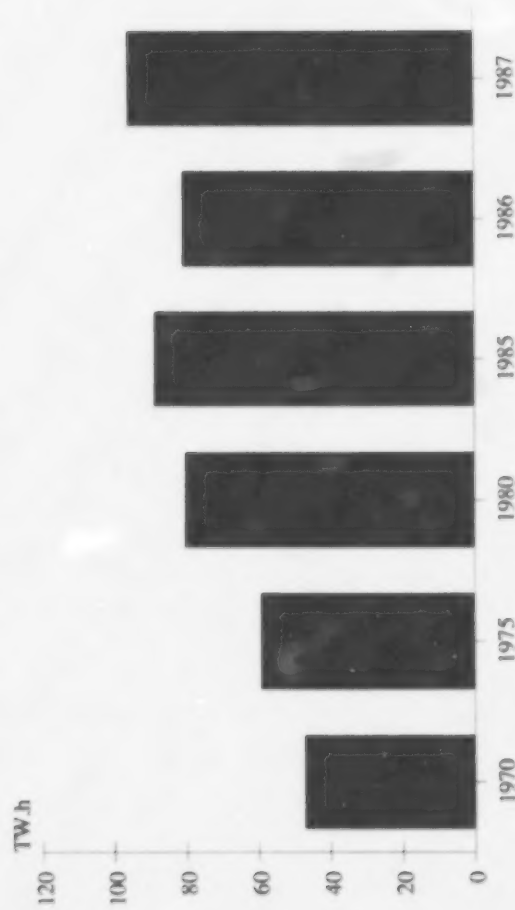
The future importance of the Canadian electrical sector as a source of acid gas emissions may, however, be somewhat overstated by figures representing its expected contribution to total Canadian emissions by the year 2005. This follows from the fact that a significant proportion of the potential for reducing acid gas emissions in the industrial and transportation sectors has already occurred, whereas little effort has been made to date to take advantage of several well defined opportunities which exist to achieve substantial reductions in both SO_2 and NO_x emissions from electricity generation.²⁹ These

TABLE 6.5
CANADIAN SULPHUR DIOXIDE EMISSIONS
BY CATEGORY, 1970-1985
(kilotonnes)

Source	1970	1972	1974	1976	1978	1980	1985
Industrial	5 045	4 689	4 250	3 717	2 851	3 090	2 572
Fuel Combustion Other than Utilities	1 047	1 014	987	882	839	624	281
Fuel Combustion by Utilities	502	543	522	608	705	761	736
Transportation	84	130	123	114	118	136	95
Other	-	1	1	1	1	1	2
Total	6 678	6 377	5 883	5 322	4 514	4 612	3 686

SOURCES: (1) Environment Canada, *Emissions and Trends of Common Air Contaminants in Canada, 1970-1980* (Ottawa: Environment Canada, September 1986); and (2) Environment Canada, 1985 unpublished data.

Figure 6.6
Fossil Fuel Generation of Electricity
in Canada, 1970-1987



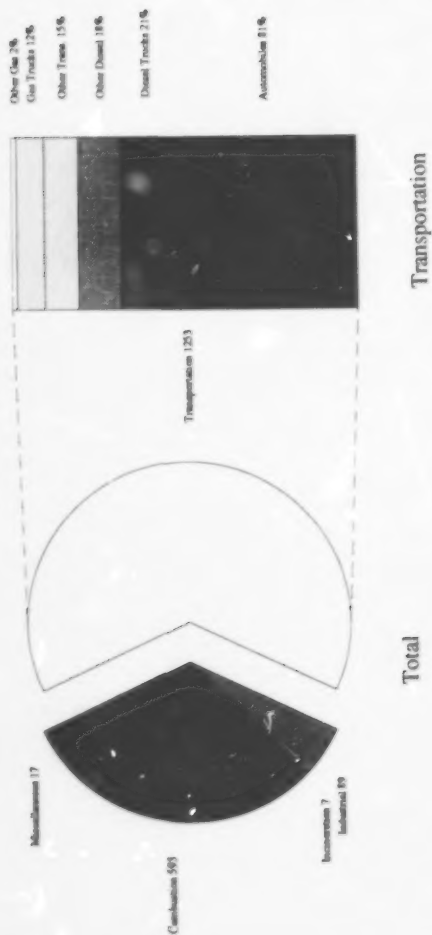
SOURCE: Figures represent average of "low" & "high" forecasts. NEB, Supply Demand, 1987-2005.

TABLE 6.6
CANADIAN NITROGEN OXIDE EMISSIONS
BY CATEGORY, 1970-2005
(kilotonnes)

Source	1970	1972	1974	1976	1978	1980	1985	2000	2005	2005/1985
Industrial	32	35	47	35	43	49	89	73	82	0.92
Fuel Combustion Other than Utilities	339	366	388	351	363	338	357	398	427	1.20
Fuel Combustion by Utilities	149	163	164	197	198	231	236	371	482	2.04
Transportation	793	892	944	979	1 060	1 077	1 253	1 214	1 310	1.04
Other	16	13	15	19	21	21	24	31	34	1.42
Total	1 329	1 469	1 558	1 581	1 685	1 716	1 959	2 087	2 335	1.19

SOURCES: (1) Environment Canada, *Emissions and Trends of Common Air Contaminants in Canada, 1970-1980* (Ottawa: Environment Canada, September 1986); (2) Environment Canada, 1985 unpublished data; and (3) Environment Canada, 2000 and 2005, Conservation and Protection Branch, Report No. 2.2, *Nox Emission Projections - 1985-2005* (Ottawa: Ontario, January 1989), p. 7.

Figure 6.7
Nitrogen Oxides Emissions 1985
(kilotonnes)



SOURCE: Environment Canada,
 Conservation and Protection, 1989.

opportunities, which include the application of conventional acid gas control measures, advanced clean coal technology, as well as the use of low sulphur coal, are examined in Section 6.5.

Estimates of emissions of VOCs, excluding methane, amounted to 1800 kilotonnes in 1985. Figure 6.8 illustrates the national distribution by source sector.

As with NO_x , transportation is also the major contributor--gasoline-powered vehicles account for about 40 percent of the national total with other transportation sources (including the off-road use of transportation-type engines) contributing an additional 10 percent. The other major contributors are industrial processes (14 percent), the miscellaneous category which includes fuel marketing operations (6 percent), solvent usage (16 percent) and fuel combustion (9 percent).³⁰

6.4.2 Provincial Distribution of Acid Gas Emissions

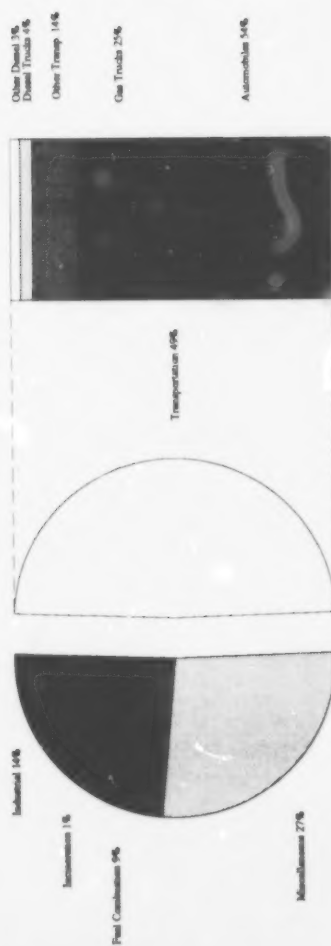
6.4.2.1 Sulphur Dioxide

The increasing importance of the Canadian electrical utilities as a source of both SO_2 and NO_x emissions will undoubtedly contribute to the pressures to reduce acid gas emissions from this sector. As indicated in Table 6.7 and Figures 6.9 and 6.10, however, the regional implications of targeting for acid gas emission reductions is complicated by the regional distribution of SO_2 , NO_x and VOC emissions.

The four most important provinces, in terms of total Canadian SO_2 emissions from electrical utilities in 1985, were Ontario (46 percent), Nova Scotia (18 percent), New Brunswick (13 percent) and Alberta (11 percent). Collectively, these four provinces accounted for over 85 percent of total SO_2 emissions from Canada's electric power sector. Moreover, the electrical sector was by far the largest single source of SO_2 emissions in Nova Scotia and New Brunswick, accounting for 76 percent and 68 percent of total provincial SO_2 emissions in each of these provinces, respectively.

While the electrical utility sector was the largest source of SO_2 emissions in the province of Saskatchewan (80 percent), electricity generation was a relatively modest source of emissions in the remaining Western provinces. As in Quebec, the electrical sector made no significant contribution to SO_2 emissions in Manitoba and British

Figure 6.8
Sectoral Distribution of
Canadian VOC Emissions



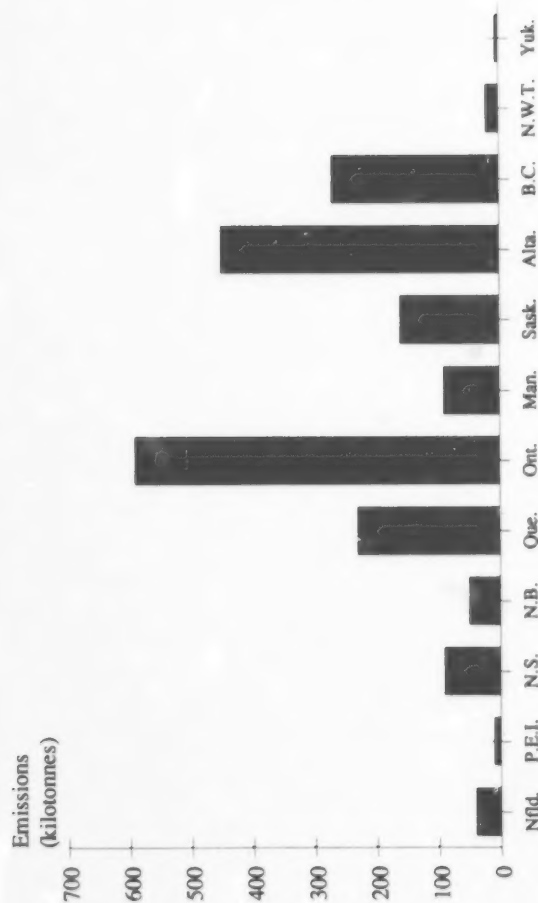
SOURCE: Federal/Provincial LRTAP
Steering Committee, July 1989.

TABLE 6.7
UTILITY EMISSIONS OF SO₂ AND NO_x BY PROVINCE,
1985

Province	Tonnes	SO ₂		NO _x	
		Percent of Emissions from all Utilities	Percent of Emissions from Province	Tonnes	Percent of Emissions from all Utilities
Newfoundland	22 267	3	51	3 808	2
Prince Edward Island	287	0	14	67	0
Nova Scotia	129 398	17	76	21 676	9
New Brunswick	93 991	13	68	7 929	3
Quebec	0	0	0	0	0
Ontario	336 707	46	23	94 600	40
Manitoba	3 880	0	1	1 781	1
Saskatchewan	68 993	9	80	35 773	15
Alberta	80 314	11	15	67 810	29
British Columbia	102	0	0	1 657	1
TOTAL	735 939	100	20	235 101	100
					12

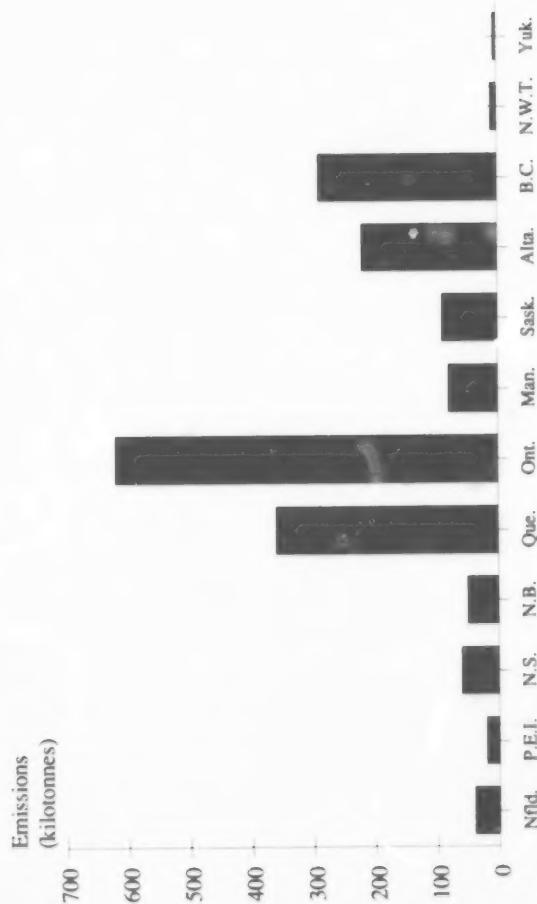
SOURCE: Environment Canada, 1985 unpublished data.

Figure 6.9
Provincial Distribution of
Canadian NOx Emissions



SOURCE: Environment Canada,
Conservation and Protection, 1989.

Figure 6.10
Provincial Distribution of
Canadian VOC Emissions



SOURCE: Environment Canada,
Conservation and Protection, 1989.

Columbia, due to the almost complete reliance on hydro power in these provinces.

6.4.2.2 Nitrogen Oxides

With the exception of Ontario, the regional nature of NO_x emissions by Canada's electrical sector contrasts sharply with that of SO_2 . Next to Ontario, which accounts for 40 percent of total emissions, the most important sources of electrical utility emissions are Alberta and Saskatchewan. Indeed, these three provinces account for roughly 85 percent of total emissions of NO_x from Canada's electrical sector.

While Ontario, together with Alberta and Saskatchewan dominate total emissions of NO_x from Canada's electrical sector, electric utilities are, relative to other sectors of the economy, still a significant source of NO_x emissions in the eastern provinces of Nova Scotia (28 percent) and New Brunswick (17 percent). In light of provincial regulations recently introduced under the acid rain program to control utility emissions of SO_2 in Nova Scotia and New Brunswick (see Section 6.5), utilities in these two provinces may well be concerned with impending NO_x targets--soon to be established under the up-coming Canadian NO_x/VOC Management Program.

6.5 Utility Emission Targets

As noted above, the electricity sector is an important and growing source of acid gas emissions in Canada, and is an area which is likely to come under increasing pressure to reduce its emissions of SO_2 , NO_x and VOCs. The nature and magnitude of emission reductions confronting each individual Canadian utility will not be known until such time as specific provincial regulations governing utility emissions are in place.

The federal and provincial governments have yet to agree on what would be a suitable provincial allocation of NO_x emissions reductions, capable of satisfying Canadian commitments under the NO_x Protocol. As such, specific limits for utility emissions are unlikely to be in place in most provinces until the early 1990s. A set of agreements on total provincial emission limits for SO_2 , however, has existed since the mid-1980s. Moreover, several provinces now have specific regulations in place governing emissions of SO_2 from electrical utilities.

As shown in Table 6.8, the Province of Ontario has set regulations which require Ontario Hydro to reduce emissions of acid gas (SO_2 and NO_x) in stages. From 1986 to 1989, total emissions must

TABLE 6.8

**UTILITY EMISSIONS TARGETS FOR ACID GAS UNDER
THE CANADIAN ACID RAIN PROGRAM**

Utility	Emissions Target
Ontario Hydro	• From 1986 to 1989, acid gas emissions must not exceed 430 000 tonnes, and of this total, no more than 370 000 tonnes may be sulphur dioxide. • From 1990 to 1993, acid gas emissions must not exceed 280 000 tonnes, and of this total, no more than 240 000 tonnes may be sulphur dioxide. • In 1994 and subsequent years, Ontario Hydro's acid gas emissions must not exceed 215 000 tonnes, of which no more than 175 000 tonnes may be sulphur dioxide.
Nova Scotia Power Corporation	• Emissions of sulphur dioxide must not exceed 160 000 tonnes per annum by the year 1994.
New Brunswick Power Commission	• Emissions of sulphur dioxide must not exceed 130 000 tonnes per annum by the year 1994.

SOURCES: Ontario Hydro, Options Available to Meet Acid Gas Limits and Selection of Preferred Options (Toronto: Ontario Hydro, Jan. 31, 1989); and Canadian Electrical Association, Generation and Research and Development Committee.

not exceed 430 kilotonnes per year; from 1990 to 1993, emissions must not exceed 280 kilotonnes; and for 1994 and beyond, total acid gas emissions may not exceed 215 kilotonnes per year.

The significance of these emission limits is characterized in Figure 6.11, which shows allowable acid gas emissions expressed in tonnes per GW.h of fossil-fired generation. As indicated, acid gas emissions are scheduled to decline under these regulations from 17.6 kilotonnes per GW.h in 1986 to 10.5 kilotonnes per GW.h by 1994. Current emission targets imply a further reduction in tonnes of acid gas per GW.h to 6.3 by the year 2005.

Limits on SO₂ emissions from the production of electric power, recently established in the provinces of Nova Scotia and New Brunswick, call for somewhat smaller, yet still significant reductions in emissions per GW.h (see Figures 6.12 and 6.13). Under the limits established by the Province of Nova Scotia, utility emissions will decline by almost 25 percent, from 20.8 tonnes per GW.h in 1987 to 15.4 tonnes per GW.h in 2005. Roughly one-half of this reduction in emissions is projected to occur by 1994.

In the Province of New Brunswick, where a limit of 130 kilotonnes of SO₂ per year has been established for the NB Power Corporation, emissions per GW.h will decline by almost two-thirds between 1985 and 2005--from 30.3 tonnes to 11.3 tonnes. The majority of this decrease occurs by 1995.

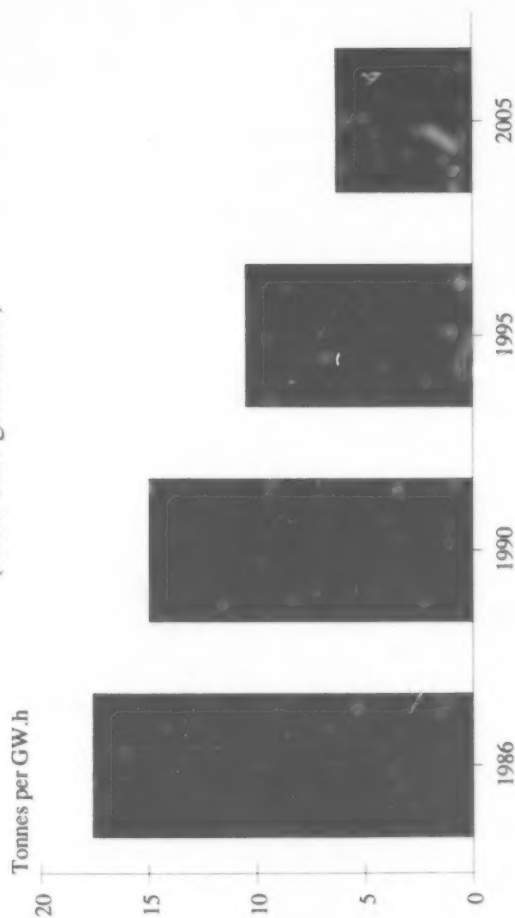
6.5.1 Industry Response

The principal conclusion to emerge from the material presented above is that Canadian utilities will come under increasing pressure in the coming decade to reduce their emissions of SO₂ and NO_x/VOC--or acid gas. Understandably, few Canadian utilities are without some form of strategy which will allow them to meet requirements for acid gas reductions, if and when such requirements are introduced. The regional dimension of these strategies is the focus of this section.

6.5.1.1 Acid Gas Abatement

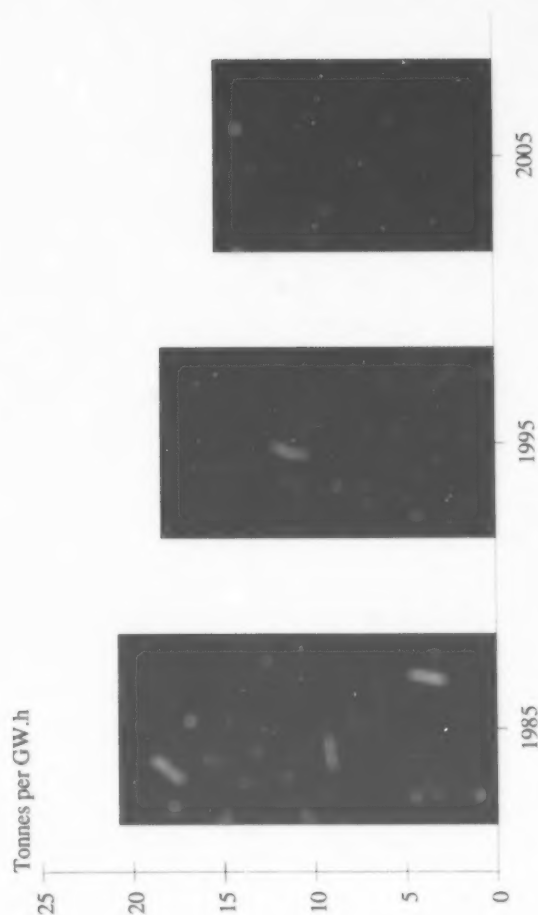
While the list of possible alternative approaches for controlling acid gas emissions is a lengthy one, the types of measures which fall under an acid gas abatement strategy, formal or otherwise, can be grouped under five main headings: (1) Coal Cleaning; (2) Low Sulphur Coal; (3) Conventional Control Technologies; (4) Advanced Clean Coal

Figure 6.11
Acid Gas per GW.h
The Ontario Target
(fossil fuel generation)



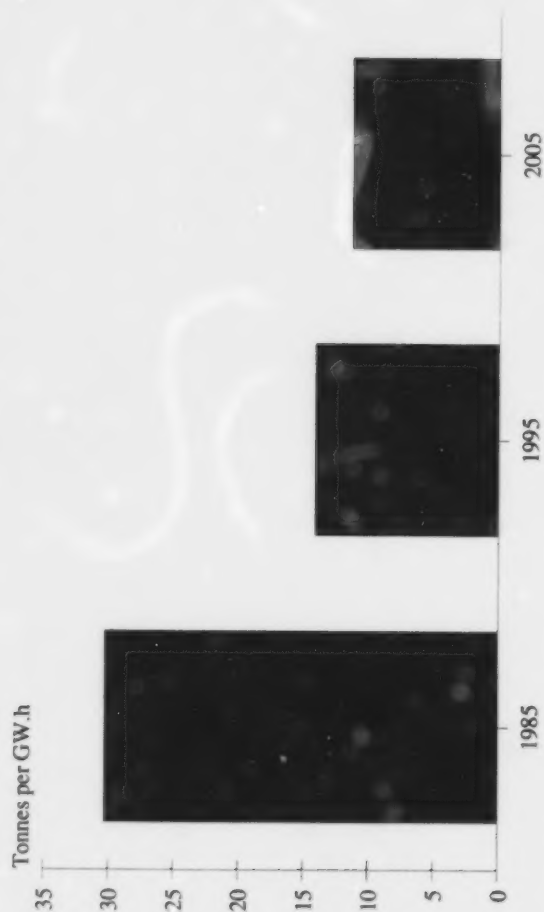
SOURCES: Ontario Hydro "Options Available to Meet Acid Gas Limits and Preferred Options" and NEB Supply Demand.

Figure 6.12
SO₂ Emissions per GW.h
The Nova Scotia Target



SOURCES: Environment Canada unpublished data and NEB Supply Demand, 1987-2005.

Figure 6.13
SO₂ Emissions per GW.h
The New Brunswick Target



SOURCES: Environment Canada unpublished data and NEB Supply Demand, 1987-2005.

Technologies; and (5) Coal Displacement. The activities in each of these areas by utilities in major coal using provinces are reviewed below.

6.5.1.2 Coal Cleaning

Coal cleaning involves the "washing" of coal before it is burned to remove sulphur and other non-combustibles (such as ash). This option, which is capable of achieving reductions in sulphur content (compared with coal at the mine mouth) of between 20 percent and 50 percent, is currently used in Ontario³¹ as well as Nova Scotia. In response to the growing demand for cleaner coal in Nova Scotia, for example, the Victoria Junction coal wash plant was recently expanded to increase its capacity from 2.9 to 4.4 million tonnes.³² Western Canadian coal is generally of sufficiently low sulphur content that coal cleaning is not required in Alberta and Saskatchewan.

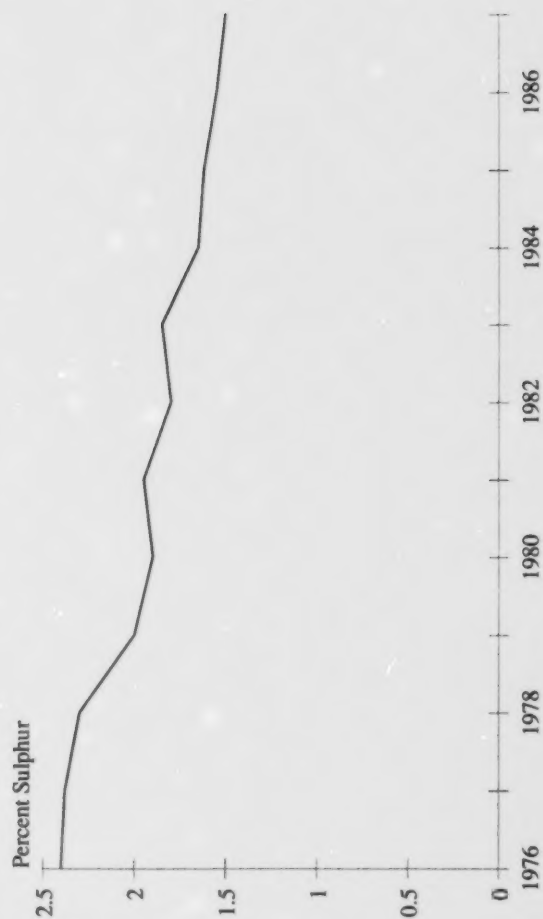
6.5.1.3 Coal Switching

Perhaps the simplest method of reducing emissions of acid gas is to switch from the use of high and medium sulphur-content coal, to low sulphur coal (see Figure 6.14). For example, switching to low sulphur coals from Western Canada and the United States has resulted in the sulphur content of imported coal burned in Ontario falling from 2.4 percent in 1976 to 1.5 percent in 1987. Ontario Hydro estimates that by burning very low sulphur coal from Western Canada instead of medium sulphur U.S. coal, it reduces SO₂ emissions by 60 kilotonnes per year, at a cost of some \$70 million.³³

The use of low sulphur coal is also an integral part of Nova Scotia's acid gas abatement strategy. As a result of efforts made to obtain lower sulphur content coal for the province's generating stations, new coal reserves currently being brought on line in Nova Scotia have sulphur contents of 0.5 percent to 2.5 percent. This compares to existing sources where sulphur contents range between 3 percent and 6 percent.³⁴

New Brunswick Power is expected to convert one or more of its three oil-fired units at Coleson Cove to coal over the next decade. This will allow for the use of low sulphur coal which could result in a possible 50 percent reduction in the SO₂ emissions from the Coleson Cove station.

Figure 6.14
Coal Sulphur Content
Ontario Hydro, 1976-1987



SOURCE: Ontario Hydro, "Options Available to Meet Acid Gas Limits."

6.5.1.4 Conventional Control Technologies

Various technologies for reducing acid gas emissions exist today, and have been proven in full-scale commercial application across North America and Europe. The most common of these conventional technologies, and those which are of principal interest to Canadian utilities, include the use of "Low NO_x" Burners and Flue Gas Desulphurization (FGD). Both of these technologies are either in use or under consideration by utilities in each of the major coal burning provinces.

Ontario Hydro installed Low NO_x burners on all units at its Nanticoke station between 1985 and 1987, achieving NO_x emission reductions at this station of roughly 30 percent. Nova Scotia Power Commission installed Low NO_x burners at its Lingan and Point Tupper stations in the early 1980s with similar success; from 1980 to 1984, NO_x emissions from this utility were reduced by 35 percent, or roughly 11 000 tonnes per year. The use of Low NO_x burners is currently under consideration by electric utilities in New Brunswick and Alberta.³⁵

While FGD technology, often referred to as SO₂ scrubbers, has yet to be utilized by Canadian utilities, Ontario Hydro has applied to the Ontario Ministry of Environment for approval to launch a sizeable scrubber program.³⁶ Under this program, a total of up to eight FGD units would be installed and in service over the next 10 years. The first pair of these units is slated for installation at Ontario Hydro's Lambton plant in the early 1990s.

New Brunswick Power Corporation is examining the feasibility of installing FGD units on its new (Minto) coal burning unit,³⁷ while Nova Scotia Power Commission is considering the use of FGD technology for new coal-fired capacity at its Bluenose project.³⁸ Utilities in Alberta are committed to researching the feasibility of conventional FGD technology, while emphasizing the development of new alternative technologies for SO₂ reduction.

6.5.1.5 Advanced Clean Coal Technologies

Several alternative coal combustion systems are currently under development which, in experimental application, are capable of achieving the emission reductions obtained by conventional acid gas control technologies together with improved overall energy efficiency.

Clean coal technologies currently under consideration by Canadian utilities include Atmospheric and Pressurized Fluid Bed Combustion, Integrated Gasification Combined Cycle (IGCC), and Slagging Combustors. The operating characteristics of these systems, as well as conventional FGD controls, are compared to a typical pulverized coal-fired unit in Table 6.9.

As shown in this Table, conventional FGD technology produces a 90 percent reduction in SO_2 emissions combined with a decrease in plant efficiency and power output, at an incremental electricity cost of roughly 1 cent per kilowatt-hour. However, experience under the U.S. Clean Coal Program suggests that some advanced clean coal technologies are capable of achieving similar SO_2 reductions together with a moderate reduction in NO_x and a slight to moderate *increase* in energy plant efficiency and power output. In addition, each of the advanced clean coal technologies depicted in Table 6.9 achieves these results at somewhere between 10 to 80 percent of the total cost of conventional control technologies.

In order to meet its 160 kilotonne SO_2 limit by 1994, Nova Scotia Power Corporation is presently taking bids for a turnkey design of a 150-MW circulating fluidized bed (CFB) unit to be located at Point Aconi, Cape Breton.³⁹ In addition, should the utility's ambitions to export up to 1200 MW of power under the Bluenose project be realized, CFB technology will be a serious contender for the first of the new 300 MW units planned to meet these export commitments. Nova Scotia is also evaluating the feasibility of gasifying indigenous coal reserves using IGCC technology for electricity generation.

Elsewhere in Eastern Canada, New Brunswick Power has indicated an interest in CFB technology for future coal-fired units, which will allow the utility to meet its 1994 target of 130 kilotonnes of SO_2 while burning relatively high sulphur N.B. coal. An experimental CFB unit (22 MW) is currently in operation at Chatham, N.B., as a shared undertaking between New Brunswick and the federal government.⁴⁰

CFB and IGCC technologies are currently of interest in the provinces of Ontario, Saskatchewan and Alberta, together with a variety of other alternative clean coal technologies. Of particular interest is the Low NO_x - SO_2 (LNS) Burner, currently under development by Alberta's TransAlta Utilities Corporation.

TABLE 6.9
AN EVALUATION OF CLEAN COAL TECHNOLOGIES:
THE UNITED STATES CLEAN COAL PROGRAM^a

	Emission Reduction		Plant Efficiency	Power Output	Plant Life	Incremental Electricity Cost (mills/kWh)	Capital Cost (per kW)
	SO ₂	NO _x					
Conventional Coal-Fired Plant With Flue Gas Scrubber	90% and higher	No Change	Decrease	Moderate Decrease	No Change	9-11	\$180-\$200
Atmospheric Fluidized Bed Boiler	85%-90%	Moderate	No Change	10%-15% Increase	Moderate Extension	6-8	\$700-\$900
Pressurized Fluidized Bed Combustion Combined Cycle	90%-95%	Moderate	Slight Increase	40%-50% Increase	Moderate Extension	4-6	\$800-\$1000
Integrated Gasification Combined Cycle	95%-99%	Moderate	Moderate Increase	50%-150% Increase	Moderate Extension	1-2	\$1100-\$1300

SOURCE: U.S. Department of Energy, America's Clean Coal Commitment (Washington, D.C.: U.S. Department of Energy, February 1987), Appendix A.

^aConventional coal-fired electric power plant is the basis for comparison.

The LNS Burner is an advanced combustion technology which promises to economically control emissions of SO_2 and NO_x for the full range of subbituminous coals. TransAlta was initially part of a consortium of U.S. utilities working with Rockwell Corporation on the development of this technology in California. The technology has been pilot-tested and proven successful in reducing emissions of acid gas at a much lower cost than conventional technologies. TransAlta has purchased the rights to its further development, commercialization and marketing to other utilities in both Canada and the United States.⁴¹ Demonstrations under the U.S. Department of Energy's Clean Coal Technology program and in cooperation with Esso Resources at Cold Lake, Alberta are being undertaken to prove up this technology for commercial application.

6.5.1.6 Coal Displacement

In contrast with strategies involving the use of conventional and non-conventional control technologies under consideration in each of the major coal-fired generating provinces, coal displacement as a strategy for reducing acid gas emissions is currently being pursued only in the province of Ontario. Ontario has identified various options to reduce coal-fired electricity generation. These include the increased use of nuclear power, demand management, hydroelectric development, greater imports from Quebec, Labrador and Manitoba, as well as export reduction.⁴² Ontario Hydro is also relying on imports of off-peak U.S. electricity to reduce the need to use its coal plant.

It would be extremely difficult to ascertain the extent to which each of these options has been exercised to date in response to acid gas as opposed to other economic and technical considerations. Nonetheless, it is clear that Ontario Hydro's success in reducing its emissions of acid gas has been due, in large part, to its ability to substitute nuclear power for existing coal-fired generating capacity.

The comparative attractiveness of coal displacement as opposed to alternative options for reducing acid gas emissions, in particular the use of conventional control technology, is explored in the following section.

6.6 Implications for Fossil-Fired Generation

Having reviewed the environmental concerns with respect to fossil-fuel fired electricity generation, as well as the nature of various pressures facing Canadian utilities to reduce their SO_2 and NO_x

emissions, the question arises as to whether any specific conclusions can be drawn with respect to: (i) the future costs of fossil-fired electricity generation; and (ii) the future demand for fossil-fired generation in Canada. Some light may be shed on these issues by contrasting the experience of Ontario with that of the coal-rich provinces of Nova Scotia and New Brunswick.

6.6.1 Ontario

Ontario Government regulations require Ontario Hydro to reduce its emissions of acid gas from a peak of 531 kilotonnes in 1982 to a maximum of 215 kilotonnes by 1994, and maintain emissions at or below 215 kilotonnes thereafter. In light of these stringent emissions limits, which imply a reduction from existing emissions of roughly 60 percent, Ontario has little choice but to back out of fossil-fired generation or apply available control technologies to much of its existing coal-fired capacity. The latter option, which is highly favoured as a short-term strategy for the control of acid gas,⁴³ is likely to impact significantly on the costs of coal-fired generation in the province.

As discussed in the previous section, Ontario Hydro plans to have up to eight FGD units along with eight Low NO_x control units in service by the year 2000. The implications of the expenditures associated with these measures for the future cost of coal-fired electricity generation in the provinces, as well as electricity rates, are presented in Table 6.10. As indicated, total annual costs associated with the use of conventional Low NO_x and FGD technology amount to just over \$200 million per year over the 1989 to 2000 period, peaking in 1996 at \$467 million. The total cumulative cost of these expenditures is \$2.5 billion by the year 2000.

The ratio of annual acid gas expenditures to the output of electricity from fossil-fired plants in Ontario provides some indication of the overall impact of these expenditures on the cost of coal-fired electricity generation in the province. Based on the National Energy Board forecast of fossil fuel-fired electricity generation of 21 674 GW.h for 1995,⁴⁴ the acid gas related expenditures presented in Table 6.9 represent an additional cost of roughly 1.7 cents per kW.h. This translates into an increase in the costs of electricity generation from a conventional coal-fired station of over 40 percent.⁴⁵

While the increase in the cost of Ontario Hydro's coal-fired electricity generation is substantial, the expected increases in Ontario's overall electricity rates are relatively modest. As shown in

TABLE 6.10
ONTARIO HYDRO
ELECTRICITY PRICE IMPLICATIONS OF
FUTURE EXPENDITURES
(\$ millions per year)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Capital													
Flue Gas Conditioning	34.9	13.1											48.0
Flue Gas Desulphurization	2.5	11.9	25.9	90.9	176.5	171.2	217.6	293.9	209.6	62.1			1262.1
NOx					41.8	48.6	56.1						146.5
Total	37.4	25.0	25.9	90.9	176.5	213.0	286.2	350.0	209.6	62.1			1456.7
OM&A													
Flue Gas Conditioning	4.5	7.1	7.1	7.5	8.0	5.6	6.0	3.2	3.4	3.6	3.9	4.1	56.9
Flue Gas Desulphurization					14.6	16.0	29.8	52.2	71.1	75.3	80.7		339.6
NOx													
Total	4.5	7.1	7.1	7.5	8.0	20.2	22.0	33.0	55.6	74.7	79.2	84.8	396.5
Fuel Premium	24.6	28.8	43.6	85.0	68.7	79.3	83.9	60.7	54.6	35.9	42.1		607.2
Total Annual Cost	37.4	54.1	61.8	142.0	269.5	302.0	367.4	466.9	325.9	191.4	115.1	126.8	2460.4
Rate Impact %	0.0	0.5	0.6	0.8	1.4	1.7	2.0	2.4	2.7	2.9	2.6	2.5	

SOURCE: Ontario Hydro, Options Available to Meet Acid Gas Limits and Selection of Preferred Options (Toronto, Ontario: Ontario Hydro, January 31, 1989).

Table 6.10, electricity rates are expected to increase gradually, showing the largest single percentage increase in 1998. The divergence between the increased cost of coal generation and the overall increase in electricity rates is explained by the fact that fossil-fired generation is expected to provide less than 20 percent of Ontario's total electricity requirements over the 1989 to 2000 period.⁴⁶

It would be an extremely difficult exercise to determine the actual extent to which coal's expected decline in the province of Ontario is related to the increased costs of acid gas abatement. The diminishing importance of coal-fired electricity generation is fully consistent with the utility's overall Acid Gas Control Strategy. The latter involves taking full advantage of every opportunity to displace coal-fired generation with all existing alternatives. Clearly, the added costs of acid gas controls will factor significantly into Ontario's future planning for major new capacity additions.

6.6.2 Nova Scotia and New Brunswick

In contrast to Ontario, the provinces of Nova Scotia and New Brunswick have recently agreed to emission limits for SO₂ which are substantially above current utility emissions in both provinces. Consequently, large-scale measures to control acid gas emissions in these provinces may not be necessary in advance of significant capacity expansion planned for later in the coming decade.

The additional time afforded the eastern provinces to achieve acid gas emission reductions may play a crucial role in determining the future costs of meeting acid gas emission targets. This stems from the fact that emerging clean coal technologies appear capable of achieving reductions in SO₂ and NO_x comparable with conventional technology at a much lower cost.

The existence of substantial industrial and employment benefits associated with the further development of indigenous coal reserves, in both Eastern and Western Canada, will serve as a significant incentive to increase expenditures on coal research and demonstration (R&D) in Canada. In turn, increased R&D may significantly accelerate the commercialization of advanced clean coal technologies.

Should clean coal technologies prove as efficient in reducing SO₂ and NO_x emissions as experience under limited application to date would suggest, then significant progress will have been made to

restore the comparative advantage of coal as a source of electricity generation, particularly in Eastern Canada.⁴⁷

6.7 The CO₂ Question

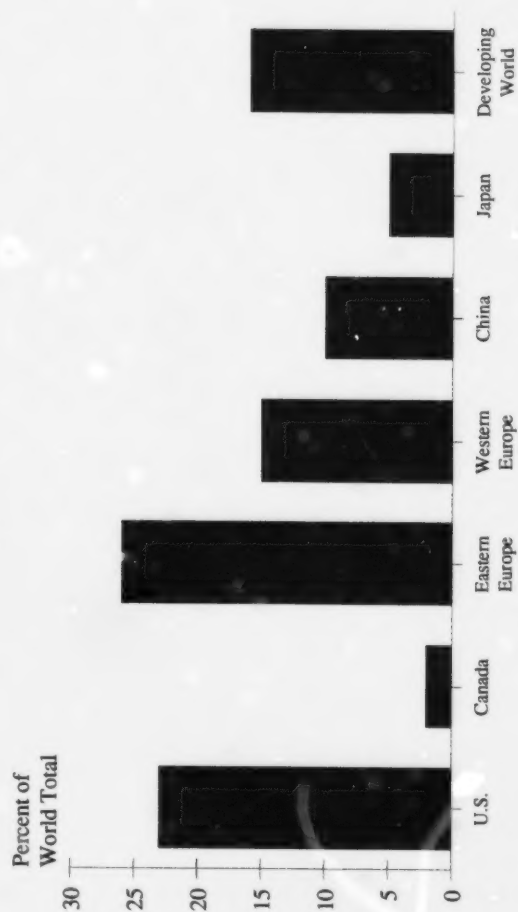
Earlier in this chapter, the enormous uncertainty regarding the "greenhouse effect" was discussed and it was concluded that much additional information would be required before a firm consensus regarding the cause and consequences of global warming could be established. At the same time, however, it was shown that a large and concerted effort is currently being made by Canada and other countries to evaluate the possible consequences of global warming and explore "alternative options" and strategies for ameliorating this problem.

6.7.1 The Dimensions of the Problem

To gain some appreciation of the possible nature of these "alternative" options and their possible ramifications, it is important that the following points be emphasized:

- Global emissions of CO₂ are widely dispersed over different regions of the developed and developing world. As shown in Figure 6.15, Canada's contribution to global CO₂ emissions is estimated at less than 2 percent.
- Unlike SO₂ and NO_x emissions, there is no proven control technology currently available for reducing CO₂ emissions. Rather, in the absence of reduced growth in energy demand, fuel switching and improved energy efficiency are the only known means of curbing global CO₂ emissions.
- The scope for achieving significant improvements in energy efficiency and a consequent reduction in CO₂ emissions varies widely from one country to the next. Many less developed countries (LDCs) currently lag decades behind Canada and other industrialized countries in terms of overall energy efficiency.
- The destruction of the world's tropical forests and this contribution to global warming must also be recognized. Deforestation contributes about 20 percent of the carbon dioxide being added to the atmosphere and is increasing.⁴⁸
- Scientists have also detected increases in other, even more potent greenhouse gases than CO₂, notably CFCs, methane and nitrous oxide. These stem from a broad range of sources, such as swamps, fertilizer, landfills, rice paddies, and industrial processes. Although each

Figure 6.15
Industrial CO₂ Emissions - 1985
by Country/Region



SOURCES: World Resources Institute and International Institute for Environment & Development, World Resources 1988-89.

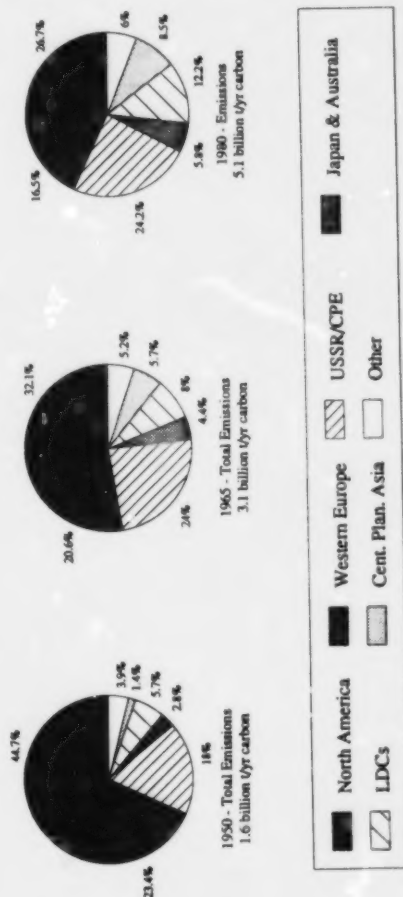
of these gases exists in the atmosphere in far smaller quantities than does carbon dioxide, their greater heat-absorbing properties mean that together they now have nearly as much greenhouse potential, in effect doubling the rate of projected climate change. The concentration of two of these gases is growing even more rapidly than carbon dioxide: 1 percent annually in the case of methane and 5 percent or more annually for CFCs.⁴⁹

These observations suggest that: (1) Canada could make a *substantial* contribution towards achieving reduced global emissions of CO₂ by channelling resources towards the development of energy efficiency in less developed countries; and (2) any action taken unilaterally by Canada will do little to solve the CO₂ problem.

In much of South East Asia, for example, it is estimated that the average efficiency of fossil-fuelled electricity generation is less than 70 percent of that achieved in Canada. Moreover, the cause of such inefficiencies is often a simple lack of training and knowledge, or machinery and equipment essential to the monitoring and maintenance of modern electrical plants. The relatively *modest* expenditures required to address such inadequacies might well pay large dividends in terms of improved energy efficiency and reduced CO₂ emissions. These expenditures could conceivably also apply as credits to Canada's own domestic efforts to reduce CO₂ emissions. The "credits trading" option seems particularly credible as: (1) the problem is a global one; and (2) the unit cost of achieving a given reduction in emissions will be less costly in LDCs than in industrialized countries. This strategy would also allow industrialized countries sufficient time to develop "commercial" clean coal technologies, "safe" nuclear power, "coordinated" regional power trade and "effective" conservation and DSM programs. A strategy to reduce domestic and international emissions is important owing to the changing pattern of CO₂ emissions exhibited in Figure 6.16.

Worldwide emissions of CO₂ more than tripled between 1950 and 1980, and the pattern of global contribution has been changing in parallel with the growth of industrialization. North America and Western Europe, together accounting for 68% of the CO₂ in 1950, represented only about 43% of the expanded total 30 years later. In contrast, the portion attributable to the People's Republic of China and developing countries in Africa, Latin America, and southern Asia grew from 7% to over 20% of the world total.⁵⁰

Figure 6.16
CO₂ Around the World



SOURCE: Electric Power Research Institute,
EPRI Journal, June 1988.

Importantly, as shown by Figure 6.17, Canada's electric power sector has *significantly less margin for improvement* owing to its high dependence on hydro power for electricity generation. The range of uncertainty associated with the buildup of greenhouse gases and their relative impacts necessitates fundamental analysis of all cost-effective remedies (see Figure 6.18).

Canada has established a well deserved reputation in the area of energy development and fossil fuel combustion technologies throughout the developing world and is well positioned to make a substantial contribution to greater international energy efficiency. If and when the need to reduce global CO₂ emissions becomes apparent, this comparative advantage could be exercised by the Canadian electrical sector to provide an important complement to other initiatives aimed at reducing CO₂ emissions. The prospects of continued use of coal in developing countries also suggest that Canada's coal and electric power sectors could jointly undertake initiatives similar to Japan's Coal Renaissance and Pacific Coal Flow strategies.

6.7.2 Canadian CO₂ Projections

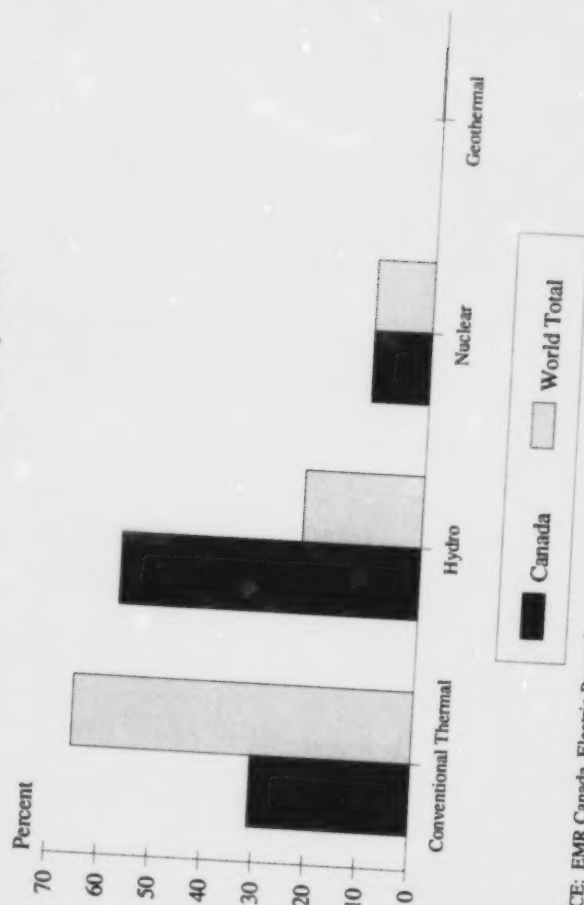
However, regardless of the existence of opportunities for achieving substantial reductions in global CO₂ emissions in LDCs, any concerted Canadian effort to limit CO₂ emissions is unlikely to ignore the possibilities for reducing emissions from domestic sources.

Canadian man-made emissions of CO₂, as indicated by Table 6.11, are forecast to increase by over 50 percent over the next 15 years. Moreover, emissions of CO₂ in the electrical sector, which currently account for roughly 20 percent of total emissions, are expected to more than double by the end of the forecast period. In this context, it is highly unlikely that as part of any global effort to control climate warming Canada could ignore opportunities to reduce projected CO₂ emissions in the Canadian electrical sector. If for no other reason, this is likely as LDC countries assert that the industrialized countries should clean up their own back yard before pointing fingers at others.

6.7.3 Fossil Fuel Displacement

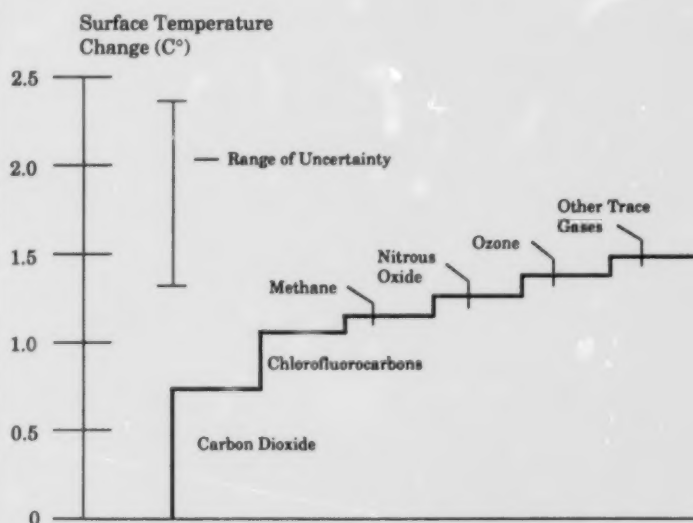
As discussed earlier, Canada's fossil-fuelled electricity generation is forecast to increase significantly by the turn of the century. In turn, this growth is responsible for the forecast increases in CO₂ emissions from the Canadian electrical sector to the year 2005. The question arises as to whether or not some proportion of this

Figure 6.17
International Comparison of Installed
Generating Capacity, 1986



SOURCE: EMR Canada, Electric Power in
Canada 1988, p. 7.

Figure 6.18
Contributions to Surface Air Temperature
Due to Greenhouse Gas Increases
1980 - 2030



SOURCE: Ian Tonens. IEA/OECD Export Seminar, April 1989.

TABLE 6.11
PROJECTED CARBON DIOXIDE EMISSIONS
(millions of tonnes of CO₂ annually)

Sector	1988	2005	1988-2005 Growth (percent)
Residential	53	61	15
Commercial	32	49	53
Industrial	121	163	35
Transportation	128	180	40
Electricity Generation	85	174	104
TOTAL	419	627	50

SOURCE: DPA Group Inc., in association with CH₄ International Ltd., RCG/Hagler, Bailly Inc., and Steven G. Diener and Associates Ltd., Study on the Reduction of Energy-Related Greenhouse Gas Emissions, Volume I - Report (draft), March 1989, p. 10.

expected increase in fossil fuel generation could be displaced with non-CO₂ contributing forms of generation, such as nuclear power and hydro generation.

6.7.3.1 Hydro Power

To the extent that a reduction in global emissions of CO₂ becomes a Canadian priority, and pressures are exerted on Canadian energy *producers* and *end-users* to realize this objective, a widespread reevaluation of Canadian hydroelectric potential appears likely. The end result may be that some proportion of Canada's remaining hydroelectric potential, previously judged uneconomic, may emerge as an attractive alternative to the expansion of fossil-fuelled capacity otherwise projected to occur in Canada over the coming decades.

Canada's potential hydroelectric capacity currently is estimated to be about 50 000 MW, or roughly 50 percent of all existing Canadian generating capacity. The development of even a small portion of this potential could make a substantial contribution to reducing forecast CO₂ emissions over the next 10 to 20 years. This would be the case regardless of whether newly developed hydro power was consumed by the province which generated it, or exported--thereby reducing the need for coal-fired generation elsewhere in Canada or in the United States.

In Chapter 5, we discussed the benefits stemming from greater interregional and international electricity trade. These potential gains occurred in large part because of the incentives which would exist under "free trade" to develop Canadian hydro power. If the further development of Canadian hydro potential, and the increased trade that goes with it, could result in a substantial reduction of CO₂ emissions (through the displacement of fossil-fuel fired generation in parts of Canada or elsewhere in the U.S.), then these benefits would have to be considered as part of the broader implications of greater integration of electric power planning within Canada and between Canada and the United States.

6.7.3.2 Nuclear Power

Nuclear power currently accounts for 12.5 percent of Canada's installed generating capacity and is the single most important source of electricity supply in Ontario. In addition, Canada's experience with nuclear power, both in terms of output performance and safety, has been consistent and highly favourable. However,

against this backdrop is the fact that in many parts of Canada considerable opposition to nuclear power development persists.

Resistance to the development of nuclear power is based largely on environmental concerns and, in particular, worries about the safety of nuclear generated power and disposal of spent fuel. This implies that any evaluation of the "opportunities" to reduce Canadian CO₂ emissions with the expanded use of the nuclear option must be treated with considerable caution. The fact, however, that any escalation in concern over the implications of increased CO₂ emissions for global climate change may yield a significant change in public attitudes to nuclear power in Canada, suggests that the opportunities to substitute nuclear power for fossil fuels in Canada cannot be ignored. In brief, approaching a reduction in CO₂ emissions must be undertaken using various technological and policy options, nuclear power being but one alternative.

6.7.3.3 Improved Efficiency

Improving the efficiency of energy consumption and fossil-fuelled combustion technology may make a substantial contribution to reducing CO₂ and other forms of atmospheric pollution.

As discussed in Chapter 3, Ontario Hydro has plans to put in place an aggressive demand-side management program, which is expected to result in as much as 4000 MW of electricity saving by the year 2000. A DSM strategy adopted in the province of British Columbia could result in a savings of an additional 760 MW. Assuming that these savings eventually translate into the displacement of equivalent quantities of coal-fired capacity, the end result could be as much as an 18 percent reduction in CO₂ emissions from electric utilities in those two provinces alone. DSM may be effective in delaying new capacity and helping to reduce the growth in CO₂ emissions but cannot be called upon to reduce the absolute level of CO₂ emissions.

Frequently, significant institutional and economic barriers stand in the way of effective use of demand management policies. To the extent that growing concern about CO₂ and other atmospheric emissions serves to increase the premium associated with environmentally benign solutions to Canada's growing electricity requirements, the incentives to overcome these barriers will be significantly increased.

The effective use of demand management policies is capable of achieving a significant reduction in the growth of Canadian CO₂ emissions. Moreover, the effects of improved demand management policies may begin to be realized almost immediately following their initial introduction. In the longer term, additional reductions in CO₂ emissions may be achievable by the introduction of advanced clean coal technologies. As indicated earlier, several emerging coal combustion technologies offer improvements in energy efficiency, with the result that less coal is burned, and less CO₂ is emitted relative to conventional coal-fired generating technology.

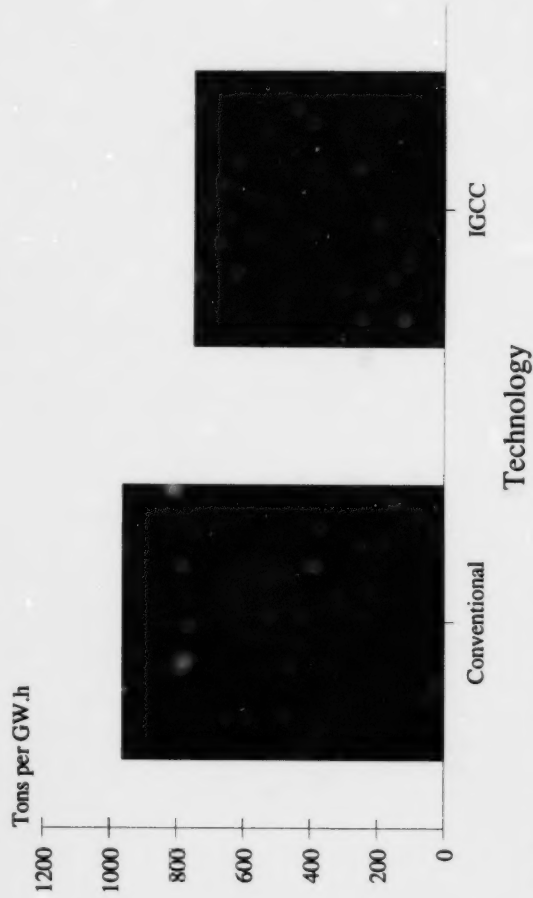
The CO₂ emissions of a conventional coal-fired generating unit and an Integrated Gasification Combined Cycle generating unit are compared in Figure 6.19. As indicated, the advanced clean coal technology generates 749 tonnes of CO₂ per GW.h in comparison to the conventional coal-fired unit, which produces 962 tonnes of CO₂ per GW.h--a CO₂ reduction of 20 percent. The possibility that Canada and other countries will take specific actions to reduce CO₂ emissions over the coming decade may contribute significantly to the incentives for development and wide-scale utilization of IGCC and other advanced clean coal technologies.^{53,54}

6.7.4 Marching Out of Step

While the dimensions of the problem are massive and considerable scientific uncertainty clouds the extent and timing of "global warming," the Canadian federal government is, nevertheless, pushing ahead very quickly. Environment Canada Minister, Lucien Bouchard, has stated that a policy for reducing greenhouse gases will be ready in the spring of 1990. "Bouchard said energy lies at the policy's core, which will have *heavy consequences on the behavior of Canadians. It will radically change their way of life.* But he said Canada will not act dramatically without an international accord."⁵⁵

What is confusing about the "March to Contain CO₂" is that politically-inspired policy is seriously out of step with the scientific and technical understanding of cause and effect. This confusion is resulting in a considerable muddle in policy planning directed to analysis of the most cost-effective ways of reducing CO₂ emissions. While transportation and industrial processes account for the lion's share (60 percent) of Canada's CO₂ emissions, the electric power industry has seemingly been slated as the "target of choice." Other "targets" may yield more significant and less costly means of reducing CO₂ emissions.

Figure 6.19
CO₂ Emissions: Conventional versus
Advanced Clean Coal Technology



SOURCE: "Environmental Emissions from
Energy Technology Systems: The Total
Fuel Cycle." DOE, April 1989.

TABLE 6.12a
CO₂ EMISSIONS BY TYPE OF FUEL
 (millions of tonnes per year)

Natural Gas	51.0
Propane	1.3
Refined Petroleum Products	18.0
Process Fuels	9.0
Coal	<u>31.5</u>
Total	110.8

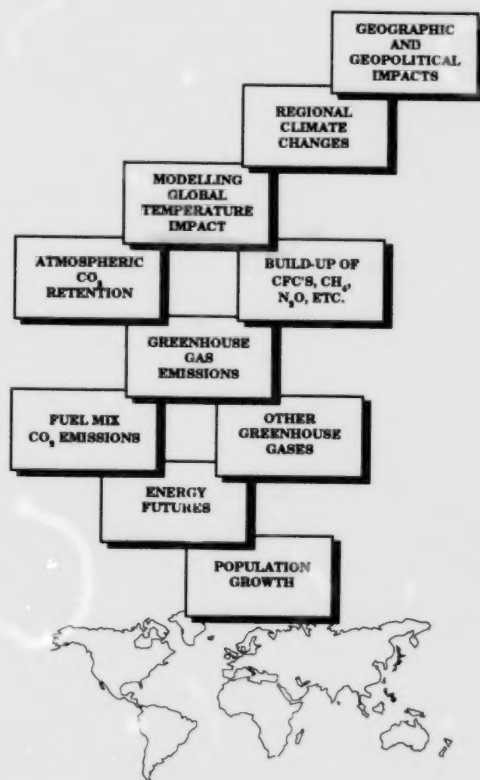
SOURCE: E. J. Wiggins and W. J. Yurko, The Greenhouse Effect and the Alberta Fossil Fuels Industry: A Discussion Paper (Edmonton, Alberta: AOSTRA, July 31, 1989), p. 8.

TABLE 6.12b
CO₂ EMISSIONS FROM NON-FOSSIL FUEL SOURCES
 (millions of tonnes per year)

Industrial Sources	
Ammonia Production	1
Lime and Portland Cement Production	0.5
Other Man-Made Sources	
Waste Burning	2-5
Natural Sources	
Decay of Plant Material and Decomposition of Soil Organic Material	300-500
Forest Fires (10-year average)	8-10
Human and Animal Respiration	15-18

SOURCE: E. J. Wiggins and W. J. Yurko, The Greenhouse Effect and the Alberta Fossil Fuels Industry: A Discussion Paper (Edmonton, Alberta: AOSTRA, July 31, 1989), p. 17.

Figure 6.20
Global Climate Change
"Piling Up Uncertainties"



SOURCE: Adapted from: Ian Torrens. IEA/OECD Expert Seminar, April 1989.

For example, Tables 6.12a and 6.12b display recent estimates of CO₂ from fuel and non-fossil fuel sources in Alberta. It is noteworthy that decay of plant material and decomposition of soil organic material account for 300-500 million tonnes of CO₂ or *some 2.7-4.5 times the total of all CO₂ emissions from fossil fuels used in the province*. These figures are *particularly significant* as four-fifths of Alberta's CO₂ emissions result from processing fuels for export to other parts of Canada or the United States.⁵⁶

The *key point* is that there are many natural and man-made sources of CO₂. *All* sources should be examined to determine the most cost-effective means of making a significant reduction in Canada's CO₂ emission levels.⁵⁷ Targeting CO₂ reductions in the electric power sector may *not* be the most cost-effective means of expeditiously reducing Canada's CO₂ emissions, particularly when all the uncertainties associated with "global warming" are considered (see Figure 6.20).

Footnotes

¹For a comprehensive review of the environmental effects of alternative sources of electricity generation throughout the entire fuel cycle, see World Energy Conference, Environmental Effects Arising From Electricity Supply and Utilization and the Resulting Costs to the Utility (London, England: World Energy Conference, 1988), Chapter 6).

²See Environment Canada, Emissions and Trends of Common Air Contaminants in Canada: 1970 to 1980, Report EPS 7/AP/17 (Hull, Quebec: Environment Canada, September 1986), for a detailed breakdown of emissions from fuel processing and refining, as well as other industrial activities.

See World Resources Institute and the International Institute for Environment and Development, World Resources 1988-89 (New York, N.Y.: Basic Books, Inc., 1988).

³Several Canadian utilities have been forced to reconsider the routing of high-powered transmission lines through populated areas as a result of public concerns over the relationship between electromagnetic fields and various health problems, including cancer (Vancouver Province, July 20, 1989, p. 6).

⁴Energy, Mines and Resources Canada, Electric Power in Canada 1988 (Ottawa: Minister of Supply and Services Canada, 1989), Table 4.1, p. 23.

⁵*Ibid.*, Figure 4.2, p. 25.

⁶In 1988, the use of refined petroleum products in Canada, mainly for transportation use, accounted for the largest share, 44 percent, of all carbon dioxide emissions even though such products comprise less than one-third of energy demand (see Figure 2.9). Natural gas accounted for 26 percent of total emissions; coal for 20 percent and wood and spent pulping liquor for 10 percent. See Federal/Provincial/Territorial Task Force on Energy and the Environment, Report on Reducing Greenhouse Gas Emissions (Ottawa, Ontario: The Task Force on Energy and the Environment), p. 25.

⁷Donald Renaud, "Public Appreciation of Energy Policy Issues" (Ottawa, Ontario: Energy, Mines and Resources, Communications Branch, May 1988).

⁸Environment Canada, "Stopping Acid Rain: The Canadian Program" (Ottawa, Ontario: Environment Canada), flyer.

⁹Sulfur dioxide (SO₂) is a corrosive gas that is hazardous to human health and has several deleterious impacts on the environment. SO₂ is emitted by both natural and anthropogenic processes; natural sources include volcanoes, decaying organic matter, and sea spray. Anthropogenic sources of SO₂ include combus-

tion of sulfur-containing fuels (e.g., coal and petroleum products) and smelting of nonferrous ores. Countries with large hydro and nuclear electricity capacities have relatively smaller contributions from power generation. Globally, natural and anthropogenic sources add roughly equal amounts of sulfur compounds to the atmosphere. See World Resources Institute and the International Institute for Environment and Development, World Resources 1988-89, pp. 163-64.

¹⁰Nitric oxide (NO) is emitted by several natural and anthropogenic processes; NO is then rapidly converted to nitrogen dioxide (NO₂) in the atmosphere. (NO_x is used to denote these two nitrogen oxides.) Nitrogen oxides damage human health and the natural environment.

N₂O is estimated to be responsible for some 8 percent of the greenhouse effect. Its impact is greater on stratospheric ozone destruction because of its long residence time (150 years): it is estimated to be responsible for 10 to 20 percent of ozone depletion. Anthropogenic sources include fertilizer use, biomass burning (e.g., tropical forest clear-burning) and fossil fuel use. Fertilizer use to increase crop yields may be the largest source of atmospheric N₂O growth. See Ian M. Torrens, "Global Greenhouse Warming: Role of the Power Generation Section and Mitigation Strategies," paper presented to IEA/OECD Expert Seminar on Energy Technologies for Reducing Emissions of Greenhouse Gases, Paris, France, April 12-14, 1989.

¹¹See House of Commons, Report of the Special Committee on Acid Rain, September 1988, p. 28.

The acidifying potential of nitric acid is considered to be about one-half that for sulphuric acid in fresh-water systems ... the two acids have comparable acidifying potential in cold-water lakes. This occurs because the biological activity which metabolizes nitrogen is inhibited in cold-water systems. This observation increases concern for the effects of NO_x and nitric acid in cold systems, a concern that is clearly pertinent to the Canadian situation.

¹²It is estimated that more than half of the acid rain in Eastern Canada originates from emissions of SO₂ and NO_x in the United States. Areas such as Muskoka-Haliburton and Quebec City, receive as much as three quarters of their acid rain from the United States. On the other hand, between 10 percent and 25 percent of acid rain in some areas of the northeastern United States is of Canadian origins (Environment Canada, "Acid Rain: The Facts").

¹³Environment Canada, "Acid Rain: The Facts."

¹⁴Ibid.

¹⁵Federal/Provincial Long Range Transport of Air Pollutants Steering Committee, Development of a National Nitrogen Oxide (NO_x) and Volatile Organic Compounds (VOC) Management Plan for Canada: Executive Summary (Ottawa, Ontario: Environment Canada, July 1989), p. i.

¹⁶Because the chemical reaction that leads to the formation of ozone depends on sunlight as well as temperature, ozone concentrations tend to be highest on hot sunny days.

¹⁷Federal/Provincial Long Range Transport of Air Pollutants Steering Committee, Development of a National Nitrogen Oxide (NO_x) and Volatile Organic Compounds (VOC) Management Plan for Canada: Executive Summary, p. 1.

In October 1988 CCME Ministers directed the Federal-Provincial LRTAP Steering Committee to develop a comprehensive plan for the management of NO_x and VOCs by the summer of 1990.

¹⁸In addition to water vapour, which is the principal absorber of infrared radiation, six gases are major contributors to the greenhouse effect:

carbon dioxide	CO ₂
methane	CH ₄
nitrous oxide	N ₂ O
tropospheric ozone	O ₃
chlorofluorocarbons	CFC-11, CFC-12

Carbon dioxide emissions from human activities are estimated to be responsible for about half of the greenhouse effect. The other half is believed to come from methane, chlorofluorocarbons, nitrous oxide, and various other gases such as the nitrogen oxides and volatile organic compounds. Emissions of greenhouse gases such as the nitrogen oxides and volatile organic compounds are very difficult to estimate, as they depend on the specific characteristics of the combustion process.

Changes in temperature on a regional scale would likely affect patterns and levels of precipitation. Most scientists expect lower levels of precipitation in the temperate zones, thus affecting agricultural practices, the ranges of forests, the flows of rivers, and not least, the capacity to generate hydroelectricity. Regional impacts will also determine the ability of plant and animal populations to adjust to climate change. See Federal/Provincial/ Territorial Task Force on Energy and the Environment, Report on Greenhouse Gas Emissions, August 1989, pp. 2, 7 and 27.

¹⁹William, Fulkerson, Energy Technology R&D: What Could Make a Difference? Part I: Synthesis Report, a study by the staff of the Oak Ridge National Laboratory (Oak Ridge, Tennessee: Oak Ridge National Laboratory, May 1989), p. 43.

²⁰Workshops were held in Villach in September/October 1987, and in Bellagio in November 1987, under the auspices of the Beijer Institute, Stockholm.

²¹Including the United States, United Kingdom, France, Germany, and the Union of Soviet Socialist Republics.

²²These agreements are between the federal government and those seven provinces east of the Saskatchewan/Manitoba border.

²³See Federal/Provincial Long Range Transport of Air Pollutants Steering Committee, Development of a National Nitrogen Oxides (NO_x) and Volatile Organic Compounds (VOC) Management Plan for Canada. Executive Summary, First Report to Canadian Council of Ministers of the Environment (CCME), Environment Canada, updated July 1989.

²⁴The final statement of the Conference also contained the recommendation for the creation of a World Atmosphere Fund, to be supplied in part by a levy on fossil fuel consumption by industrialized countries.

²⁵Federal/Provincial/Territorial Task Force on Energy and the Environment, Report on Reducing Greenhouse Gas Emissions.

²⁶A U.S. Environmental Protection Agency study presented to Congress in March 1989 has offered the first specific proposals to emerge from any U.S. government agency on measures to reduce greenhouse gas emissions. These include carbon emission fees, designed to discourage the use of fossil fuels. Under the proposed scheme, the following fees would be levied: coal, 20 percent; oil, 11 percent; and natural gas, 7 percent. The Bush Administration, Congress and the international community will study and debate the proposals before deciding whether to approve them. [See Daniel Lashof, and Dennis, Tirpak, Policy Options for Stabilizing Climate, Draft Report to Congress (Washington, D.C.: U.S. Environmental Protection Agency, February 1989).

²⁷The Special Envoys were William Davis for Canada and Drew Lewis for the United States, who were assigned to examine the problem of acid rain between the two countries and make recommendations to the governments of Canada and the United States.

²⁸SO₂ emission figures relate to provinces east of Saskatchewan.

²⁹In the transportation sector for example, Environment Canada and Transport Canada have developed new emissions standards for motor vehicles which will significantly reduce emissions of

NO_x and other pollutants. In the nonferrous metals sector, significant process improvements have already been made. In addition, the increased pyrrhotite rejection at Thompson, Copper Cliff, and Falconbridge, the expansion of acid gas plants at Inco's Iron Ore Recovery plant, and the addition of acid gas plants at Gaspé and Falconbridge, will all contribute to SO₂ reductions in the industrial sector.

³⁰Federal/Provincial Long Range Transport of Air Pollutants Steering Committee, Development of a National Nitrogen Oxide (NO_x) and Volatile Organic Compounds (VOC) Management Plan for Canada: Executive Summary, p. 15.

³¹Coal shipped to Ontario is washed at the mine mouth to reduce volume, weight and most importantly transportation costs.

³²Energy, Mines and Resources, Canada-United States Electricity Trade (Ottawa, Ontario: Energy, Mines and Resources Canada, July 1987), p. 38.

³³Canadian Electrical Association, Research and Development, Generation Committee, draft report "Advisory Panel Priorities."

³⁴The new Lingham-Phalen Collieries will produce high grade coal with a low sulphur content (Energy, Mines and Resources Canada, "Canada-United States Electricity Trade," July 1987), p. 37.

³⁵Canadian Electrical Association, Research and Development, Generation Committee, draft report "Advisory Panel Priorities."

³⁶Ontario Hydro has plans to install 8 FGD units, to be in service by 2000. These include, 4 units at Lambton, and 8 units at Nanticoke between 1994-98 (Ontario Hydro, "Option for Meeting Acid Gas Limits and Selection of Preferred Options," January 1988).

³⁷Canadian Electrical Association, Research and Development, Generation Committee, draft report, "Advisory Panel Priorities."

³⁸Under this project, up to 1200 MW of power would be generated in Nova Scotia and transmitted to New England via an under sea cable.

³⁹Canadian Electrical Association, Research and Development, Generation Committee, draft report, "Advisory Panel Priorities."

⁴⁰Energy, Mines and Resource Canada, "Canada-United States Electricity Trade," July 1987.

⁴¹*Ibid.*, p. 39.

⁴²Ontario Hydro, "Options for Meeting Acid Gas Limits and Selection of Preferred Options," January 1989, p. 13.

⁴³*Ibid.*, p. 2.

⁴⁴Based on an average of "low" and "high" case forecasts (National Energy Board, "Canadian Energy Supply Demand 1987-2005," September 1988).

⁴⁵Based on generation costs of 4 cents per kW.h of a conventional coal-fired station, without SO₂ or NO_x controls.

⁴⁶National Energy Board, "Canadian Energy Supply Demand 1987-2005," September 1988.

⁴⁷The situation is considerably different in Western Canada where very low sulphur coal is used for thermal generation.

⁴⁸Christopher Flavin, Slowing Global Warming: A World-wide Strategy (Washington, D.C.: The Worldwatch Institute, October 1989), p. 7.

⁴⁹*Ibid.*, p. 12.

⁵⁰Electric Power Research Institute, The Politics of Climate, EPRI Journal (Palo Alto, California: EPRI, June 1988), p. 7.

⁵¹Canadian Electrical Association/Energy, Mines and Resources Canada, Demand Side Management in Canada, 1989, p. 19.

⁵²Assumes that displaced coal-fired capacity would have performed with an average capacity factor of 60 percent. Percentage reduction in generation, based on the average of projected fossil-fired generation for 2005, under the National Energy Board's "high" and "low" demand forecasts, respectively.

⁵³The Canadian Energy Research Institute is currently assessing technological responses to environmental issues.

⁵⁴For a comprehensive discussion of options see E. J. Wiggins and W. J. Yurko, The Greenhouse Effect and the Alberta Fossil Fuel Industry: A Discussion Paper (Edmonton, Alberta: AOSTRA, July 31, 1989).

⁵⁵The Calgary Sun, October 26, 1989, p. 38.

⁵⁶E. J. Wiggins and W. J. Yurko, The Greenhouse Effect and the Alberta Fossil Fuel Industry: A Discussion Paper, p. 8.

⁵⁷For an excellent and comprehensive description of the problems and potential solutions to world environmental degradation, see Scientific American, "Managing Planet Earth," Special Issue, vol. 261, no. 3, September 1989.

Chapter 7

KEY FINDINGS AND CONCLUSIONS

This chapter summarizes the preceding material, cites various conclusions stemming from the discussion and identifies issues requiring future research and policy analysis.

7.1 Introduction

Electric utilities in several Canadian provinces face an increasingly tight supply/demand balance. The excess generating capacity experienced in many provinces over the past decade has been gradually worked off, requiring a number of utilities to once again face the need to make significant additions to their resource base.

This need for new electrical generating capacity will have important implications for political, economic and social issues facing Canada's electricity industry, including environmental protection, electricity trade, demand-side management and non-utility power production. The manner in which Canadian utilities will resolve each of these issues will depend, in large part, on the rate at which they must add new capacity. Provinces facing moderate pressure for new supply have greater flexibility and more time to implement new policies--whether related to environmental practices or effective demand-side management. Utilities with inadequate generating facilities to meet expected future demand will have to address these structural and policy issues in a more hurried fashion.

Canadian utilities have traditionally followed a self-reliant, demand-driven strategy in their efforts to manage the supply/demand balance in each province and to provide the lowest cost power to their customers. A utility would forecast future demand in its province, take this forecast and an associated range of uncertainty as a given and construct sufficient capacity to meet that expected demand. Demand in the utility's load area would be met almost exclusively with the utility's own generating facilities. In the past, low production costs from large-scale central generating facilities meant that little effort was given to encourage independent power production, or to supplement domestic generating capacity with firm imported power. Similarly, utilities did not take a proactive role in managing electricity

demand, but rather accepted their duty as one of supplying whatever demand existed within its service area, subject to the prevailing price structure and regulatory regime.

This traditional approach to planning is undergoing and will undergo further substantial change. Utilities will increasingly come to rely on external resources (either imported power or non-utility generation) to help meet domestic demand. Likewise, interventionist demand management practices, designed to encourage more efficient load structures and consumption practices, will also become prevalent.

These new strategies are in their infancy, however, and the economic and regulatory conditions which will shape them have yet to be fully analyzed and understood. For the most part, the existing demand forecasts and electricity generation plans of Canadian utilities do not account for expected policy changes in the areas of trade, demand management or independent power production.

The actual capacity additions undertaken in each province will depend on how Canadian utilities and their regulators respond to the growing interest in alternative approaches to the planning of future electricity supply and end use.

7.1.1 The Uncertainty of Electricity Demand

Electricity demand in Canada is being pulled by two general but competing forces. In one direction, Canada's economy has become more *energy efficient* in recent years. On average, this tends to reduce the amount of all energy required for human activity. This tendency will likely continue, motivated by economic, environmental and technological forces.

Canada's economy, on the other hand, has become more *electricity intensive*. Electricity now accounts for almost one-quarter of all energy use in Canada, as opposed to just 18 percent only 10 years ago. An estimated 80 percent of electricity demand growth over this period was the result of the substitution of electricity for other fuels. Only 20 percent was the result of an expansion of Canadian demand for energy. While new technology promotes energy efficiency in almost all cases, in many circumstances it also contributes to this growth in electricity intensity at the same time. It is far from apparent which force will exert the more decisive impact on Canada's electricity industry in the coming decade.

The aggregate electricity demand faced by Canadian utilities is ultimately composed of a wide variety of individual final uses in different sectors of the economy. These uses, in turn, are subject to a complex set of factors ranging from population growth and the expanding and changing structure of Canada's economy, to the certain but unpredictable course of technological change. Any of these factors could render the most sophisticated demand forecasts of Canadian utilities meaningless.

An important part of the challenge facing utility planners in the 1990s is to reduce the uncertainty derived from the complex nature of electricity demand, by gathering more accurate and timely demand information and by improving forecasting techniques. The challenge extends to better understanding the nature of uncertainty, and to *incorporate* this understanding directly into the planning process.

The future planning strategies of utilities will, for example, require increased efforts to maximize the *flexibility* of electricity supply to respond to unpredicted demand developments. This could include an attempt to reduce the time-lag between the decision to proceed with a new capacity addition and its in-service date by streamlining the regulatory and planning processes. Another option is to utilize less capital-intensive generating facilities such as combined cycle plants or natural gas-fired units which take less time to construct than large hydroelectric stations and nuclear power plants. Alternatively, utilities may use electricity trade to maximize their flexibility to deal with unplanned demand changes, either by selling surplus power to external customers in the event of a demand downturn, or calling back firm exports to supply the domestic market if required.

7.2 Key Findings

7.2.1 Capacity Additions

The amount of new generating capacity required by Canadian utilities through the rest of the century will surpass that experienced during the last decade. Depending on the demand forecast that is accepted, annual new capacity requirements may be greater than at any time in Canadian history, despite a generally slower rate of growth in domestic electricity demand.

The rate of capacity addition is very sensitive to assumptions regarding domestic demand growth. Total capacity additions required by the year 2000 in the high demand scenario (3.5 percent

average annual growth) are more than double those in the base scenario (2.4 percent average annual growth).

The amount of new capacity required in several provinces--Quebec, British Columbia and Manitoba--could be increased considerably with the successful completion of firm power export proposals currently being negotiated. If all of these export contracts come to fruition, the new installed capacity required by the end of the century amounts to 9000 MW more than would be required to service Canadian demand alone.

Quebec will require by far the most new generating capacity by the end of the century. Other provinces with major uncommitted capacity requirements include Alberta, New Brunswick, Nova Scotia and Saskatchewan. Ontario requires uncommitted capacity only in the high demand scenario; otherwise, committed capacity is sufficient to meet domestic demand until the year 2000 assuming that demand management and non-utility generation targets are successful.

The fuel mix of future capacity additions is likely to remain similar to the existing resource base, with hydroelectric facilities accounting for some 60 percent of all new capacity. The share of nuclear power will increase slightly by the year 2000, offsetting a fall in oil and gas-fired capacity. The share of coal-fired plants will remain virtually constant. Those general trends are, of course, dependent on Canada's response to rising concern with the environmental impact of fossil-fuel combustion.

The construction decision dates facing each provincial utility are currently uncertain and vary greatly with the assumptions made regarding future demand growth, size and timing of firm exports, and the type of fuel chosen for new facilities. Based on domestic demand alone, British Columbia, Manitoba and New Brunswick can wait until the mid-1990s before committing to the construction of new facilities. Other provinces will need to decide on new capacity additions early in the 1990s.

It must be stressed that this study focusses on a sensitivity analysis of demand and the potential implications. The figures presented are not a *forecast* of the size and timing of future capacity additions in Canada. We have not attempted to select one particular demand scenario over another, nor to determine which export projects are likely to come to fruition. Our sensitivity analysis yields important, if tentative findings.

If demand grows at the rate presently forecast by utilities, we expect a requirement for some 9000 MW of new, uncommitted capacity by the year 2000. If demand grows according to the high demand case, capacity requirements more than double. And if the various firm export proposals being pursued by several provinces come to fruition, the need for new capacity is both increased and is more imminent. In all of the scenarios that we developed, the rate of construction of new capacity in Canada is considerably greater than that experienced in the past decade. This will make it even more imperative for utilities and policy-makers to resolve fundamental issues that currently complicate the planning process--questions pertaining to environment, electricity trade, non-utility generation and demand-side management.

7.2.2 Demand Management

The risks associated with forecasting and planning for new electrical generating capacity have led some utilities to actively consider demand-side management (DSM) programs. DSM includes actions to improve system load factor and thereby reduce capital expenditures, improve capacity limitations, reduce the cost of service, and improve system efficiency and system reliability. Once a program infrastructure is in place, DSM enhances planning flexibility, as it requires comparatively short lead times for scaling the programs up or down as conditions dictate.¹ Flexibility, safety, social concerns and environmental impacts are additional factors motivating some utilities and their regulators to support DSM programs.

Recent recommendations and research are indicative of DSM's evolution and increasing importance. However, many DSM programs are only in the conceptual/development stage and it will take time before their impacts and costs are clearly known. For example, it has been recommended that conservation supply functions be developed and incorporated in Ontario Hydro's planning process. Monitoring and post-audit systems to determine the amount of savings actually achieved under various DSM programs are also suggested as a means of better quantifying DSM potential. Many analysts believe that these initiatives would greatly reduce the current uncertainty surrounding the impacts and relative costs of various DSM programs.

The growing willingness to consider supply alternatives such as demand-side management and non-utility generation suggests that the development of competitive bidding schemes on the demand or

supply side, similar to those under development in the United States, will materialize in Canada. The success of efficiency programs in the United States has also sparked support in Canada for compulsory energy efficiency standards rather than voluntary or price-driven measures. Taken together, these initiatives suggest that comprehensive least-cost planning will eventually materialize in many regions across Canada.

While the future of DSM appears promising, its rate of development is uncertain due to its rudimentary growth to date. However, pressures are mounting for significant growth in the coming decades as utilities and their regulators seek greater efficiencies in the production and end-use of electricity. Strategies aimed at ameliorating growing concern with the environmental impacts of fossil-fuel combustion will add immediacy to this pursuit of greater system efficiency.

Fundamental market research and demonstration (R&D) is essential and is presently underway in many parts of Canada, though critics argue that more must be done. This R&D will provide Canadian utilities with a better understanding of the actual costs and value of specific DSM programs. Comprehensive least-cost planning and competitive bidding for new supply seem destined to become fundamental in Canadian electric power planning. These practices have been under development in the United States for some time and could provide important insights to program development in Canada.²

7.2.3 Non-Utility Generation

Non-utility generation (NUG) is a relatively new aspect of electricity planning in Canada. For many decades, Canada's electric utilities have supplied electricity in the most cost-effective manner by capitalizing on economies of scale. Up until the 1980s, independent power producers were not competitive with utilities due to the low costs inherent in electricity production from large-scale generating stations. However, increasing construction costs, economic and regulatory uncertainties, and changes in technology have altered this situation. Factors such as higher inflation and interest rates, more stringent safety and environmental standards, volatile fuel prices, and unexpected changes in electrical demand growth have exerted upward pressure on production costs, which in turn has reduced the attractiveness of adding large new blocks of conventional generating capacity. These factors have called increasing attention to the potential role of non-utility generation, particularly cogeneration.

Non-utility generation is not, however, a substitute to central utility generation. In many provinces, NUG could not alone match the generation supply required to meet forecast levels of electricity demand. Moreover, NUGs are not committed to serve in the same way as a central utility. Reliability of NUG electric power supply may also limit its economic attractiveness. Determining a price that reflects the "social" value of non-utility generated power is also a complex issue. While experts generally agree that the buyback rates offered to non-utility generators should reflect "avoided cost principles," it is not clear how these rates should be set or by whom.

Four provinces currently support NUG: Ontario, British Columbia, Alberta and Quebec. Ontario Hydro, for example, is diversifying its generation mix and plans to acquire about 1000 MW from non-utility generators by the year 2000, although the Ontario Ministry of Energy cites 2000 MW as a more realistic figure. In December 1988, B.C. Hydro requested proposals for NUG supply for its integrated system of up to 150 MW. It followed up later with a purchase policy indicating that requests for proposals totalling 25 MW (from projects less than 5 MW) will be issued annually.

While some interest in NUG is emerging in other provinces, utilities have generally been unsupportive of independently generated power, citing reliability as their primary concern. Further development seems likely, however, as the availability of inexpensive conventional sources of supply diminishes and utilities are forced to consider alternative supplies. Greater recognition of the potential of NUG, together with a growing number of independent power suppliers, could eventually lead to comprehensive power purchase policies and the abandonment of existing project-by-project negotiations. These developments go hand-in-hand with the evolution of supply- and demand-side competitive bidding programs.

While interest in NUG is emerging across Canada, many questions remain unanswered. There is, for example, considerable regional diversity in the perceived need for NUG and the perceived reliability of electricity offered by small power producers. An interesting case is Alberta, where a 5-year R&D program is underway to assess the advantages and disadvantages of greater reliance on non-utility generation.

The U.S. experience with NUG, fostered by proactive legislation, is an important point of departure for Canadian utilities and policymakers. For more than a decade, U.S. non-utility generation has

been actively supported under PURPA. While this experience has not been entirely positive, Canadians could benefit from modifying some U.S. programs to Canadian conditions.

Competitive bidding programs are a case in point. An appraisal of the Federal Energy Regulatory Commission's (FERC) competitive bidding proposals and those addressing the calculation of avoided costs is relevant to Canada. Also, recently completed studies by the FERC on transmission pricing and access would provide valuable insights on means of addressing Canadian market impediments to non-utility generation and interprovincial electricity trade.

Despite the insights gained in looking to experiments south of the border, *Canadian* research is needed to pinpoint the role for non-utility generators in electricity supply for the 1990s. There is a clear need to quantify the amount of electricity that can be provided by independent power producers and to evaluate the number of megawatts that could be supplied at different price levels. Issues such as the reliability and availability of NUG power supply, the provision of market access and appropriate purchase rates, as well as the appropriate role of regulatory agencies, are fundamental and require analysis and demonstration.

7.2.4 Electricity Trade

The economic benefits of electricity trade and greater coordination in electric power planning lie largely in the economies of scale and the advantages of the diversities in load, risks and operating costs. Capital costs are reduced through the use of larger generating units which cost less to build per unit of output, and through the lower reserve margins which result from reducing the ratio of generating unit size to combined system peak load. Operating economies are gained through the load diversity of the combined systems, reduced operating costs per unit of output, and more complete use of the lowest cost generation available to the systems. Additional savings are possible through coordination of construction programs which minimize the costs of temporary excess capacity resulting from the addition of generation in stepwise blocks. Reliability benefits stem from a reduction in reserves required to achieve a given level of reliability, or as an increase in the level of reliability of the coordinated systems.

The benefits of electricity trade are substantial. A recent U.S. evaluation showed total national savings of \$15 billion per year in the bills electricity consumers paid in the last few years, resulting from

inter-utility coordination and power pooling. If not for the intercompany coordination presently practised in the United States, about 14 percent more generating capacity would have been required to maintain adequate reliability.

CERI's modelling of unrestricted electricity trade between Canada's provincial utilities indicates savings of over \$3 billion (\$1988 Cdn. relative to the base case. Greater exports of Canadian power to the United States could save upwards of \$26 billion in capital and operating expenses and generate significant revenues for Canadians. Maintaining security of supply through a diversity of supply sources and reducing emissions and their impact on the environment are significant trade benefits which were not accounted for in our modelling simulations.

While a number of past studies have pointed to the benefits of integrated power planning, serious effort in support of greater interprovincial trade is only now starting to emerge. Increasing recognition of the benefits to be derived from greater trade is required so that consumers have a more balanced understanding of the benefits and costs of this supply option. The planning environment of electric utilities and their regulators must also be broadened to encompass electricity trade as an important component of least-cost generation planning. Electricity trade and coordinated electric power planning should be considered on an equal footing with options such as conservation, demand-side management, non-utility generation and conventional generating capacity.

To augment Canadian energy efficiency and reduce future electricity prices, a comprehensive examination of the costs and benefits of greater inter-utility trade and coordination should be undertaken. Owing to the cost and complexity of the issue, our study could only go part way to addressing "net" trade benefits. In fact, this broader focus appears imminent as the National Energy Board gears up to review and report on ways to:

- enhance interprovincial trade in electricity;
- encourage greater cooperation between utilities in systems planning and development; and
- enable buyers and sellers of electricity to obtain commercial access to available transmission capacity through intervening provinces for wheeling purposes.

The NEB will shortly announce how it will examine these issues.

7.2.5 Environment

All of the above are important to the most pressing issue facing Canada's energy industry--the environment. The environment will become increasingly important in utility planning, rivalling electricity demand and fuel costs as the single most important source of uncertainty facing Canadian utilities over the coming decade. In fact, environmental concerns are the cornerstone of increasing interest in DSM, NUG and electricity trade as means of improving efficiency in production and end-use of Canadian electric power.

Environmental concerns and their impact on Canadian electric utilities pertain to the following areas:

- lack of information regarding the benefits and costs of remedying environmental externalities;
- the future course of public policy; and
- public attitudes towards environmental issues in Canada.

Public policies towards the environment will be affected as well by the need to achieve wide-scale international coordination on many environmental issues.

Environmental concerns in the form of public and political pressure, combined with regulations established over the past 15 years, will continue to influence the development of new hydro and nuclear power facilities. However, environmental concerns in the 1990s will focus on controlling atmospheric emissions such as sulphur dioxide (SO₂), nitrogen oxide (NO_x) and carbon dioxide (CO₂), major components of acid rain, elevated ozone and global warming. As electric utilities are important sources of emissions of SO₂, NO_x and CO₂, pressures to control these emissions will impact the operation of existing fossil-fuelled generating stations and will contribute to the uncertainty in planning Canada's future generation and technology mix.

The prevalence of fossil-fuel fired electricity generation throughout most of Canada, and the fact that future capacity additions in many provinces will likely be dominated by fossil fuel facilities, means that the regulation of atmospheric emissions will emerge in the

1990s as a dominant environmental issue facing the Canadian electrical sector as a whole. This will force active consideration by all parties--utilities, public utility boards and governments--to give greater recognition to the impacts of regulatory oversight and to factors which promote greater efficiency, both of electricity supply and electricity end-use.³

Pressures to reduce atmospheric emissions will be exerted by local, provincial and federal ambient air quality standards, public opinion, and, most importantly, specific emission reduction targets established in response to international protocols and agreements.

For example, under the NO_x Protocol of 1988, Canada has agreed to reduce its NO_x emissions to 1987 levels by 1996. While specific federal/provincial agreements to implement this policy have yet to be determined, it is expected that Canadian utilities will be asked to bear a significant share of the targeted reductions.

The Canadian government is involved in evaluating the CO₂ problem and is examining CO₂ emission reduction targets and abatement strategies. While an international agreement on CO₂ emission reduction is not expected in the near term, utility planning decisions in the 1990s may be influenced by such a possibility, as any suggested targets for reducing CO₂ emissions would have far-reaching implications for the future generation of Canadian electric power, and for the Canadian economy as a whole.

The extent and nature of the response to existing and anticipated emission reduction targets have varied widely across Canada. In response to Ontario Government regulation, Ontario Hydro has introduced an acid gas program which involves the following measures:

- reduce sulphur content of coal;
- introduce conventional control technologies such as scrubbers and low NO_x burners in existing facilities;
- examine the potential for the use of advanced clean coal technologies; and
- displace coal with demand-side management, nuclear power, hydro generation, increased trade and non-utility generation.

Other Canadian utilities have adopted one or more of the acid gas abatement strategies involved in the Ontario Hydro Program, including the use of low sulphur coal and the consideration of conventional and advanced clean coal technologies. Coal-committed provinces, such as Nova Scotia, New Brunswick, Saskatchewan and Alberta, are understandably interested in developing clean coal technologies, to ensure the long-run viability of their coal resources.

The costs of reducing acid gas emissions in Ontario may increase the costs of coal-fired generation by as much as 20 percent, and thus accelerate the province's move away from coal generation. The declining importance of coal in electricity generation in Ontario is expected to mean that Ontario can meet its acid gas emission commitments with only modest increases in electricity rates. In other parts of Canada, however, notably in those coal-committed provinces which do not have ready access to low sulphur coal and where significant new capacity may be required over the near term, acid gas emission controls will result in the cost of coal-fired generation increasing substantially.

However, the incremental costs of acid rain abatement may not be large enough to offset the perceived benefits of coal-fired generation in provinces like Nova Scotia, New Brunswick, Saskatchewan and Alberta. Here the development of indigenous coal resources is a fundamental component of energy and economic development strategies. Apart from the economic spin-offs associated with continued use of coal in some of these provinces, coal is also the most economic generation alternative. These provinces can be expected to accelerate the move towards advanced clean coal technologies which, according to many industry specialists, offer a solution to the environmental problems associated with coal combustion.

One of the *principal* sources of uncertainty facing the electrical sector today stems from escalating concern over increasing CO₂ concentrations on global warming. While Canadian utilities have generally adopted a "wait and see" approach to the CO₂ problem, any demonstrable increase in public concern over global warming would undoubtedly force Canadian utilities to consider the implications of CO₂ controls for future planning decisions.

Unlike acid gas, no feasible technology currently exists for controlling CO₂ emissions in the combustion or flue gas stages. It would appear that for the foreseeable future, the options available for reducing CO₂ emissions in the electrical sector

are limited to fuel switching and improved efficiency, both in fossil-fuelled combustion and electricity end-use.

Advanced clean coal technologies are currently in the demonstration stage. While they appear capable of offering sizeable improvements in generating efficiency, it is unclear whether efficiency improvements of this nature alone would be capable of achieving (as-of-yet unspecified) reduction targets. More likely, a combination of fuel switching and improved efficiency at both the production and end-use stages will be required to achieve a meaningful reduction in CO₂ emissions. To some extent, we may simply have to adjust to living in a warmer world.

Increased uncertainty with respect to the future costs of alternative forms of electricity generation will provide utilities with an incentive to minimize the need for, or postpone decisions regarding new capacity additions. In common with developments in the United States, it is likely that Canadian utilities would place greater emphasis on power pooling, demand-side management, independent power production (particularly cogeneration) and energy efficiency programs in various end-use sectors.

7.3 Conclusions

The objective of this research project was to assess some of the more important issues bearing on the future development of Canada's electric power industry. The underlying emphasis has been one of greater rationalization or efficiency in the provision and end-use of Canadian electric power. The cornerstone of this interest in greater efficiency stems from a wide-ranging concern with the environmental impacts of energy production and use.

Canada's electric utility industry has been buffeted by numerous changes in economic climate and regulatory and political attitudes over the past two decades. Still, the industry remains a vibrant and fundamental component of our economic growth and Canada's high standard of living. Canada's electric utilities have attempted to minimize power costs and provide high levels of reliability to their customers. This least-cost operating strategy, reinforced by government regulation, has in many cases caused utilities to respond conservatively to new pressures and changing trends. Some suggest far too conservatively.

While least-cost planning remains the hallmark of utility planning, greater economic uncertainty has complicated the assessment of the least-cost generation mix required to meet the forecast, but uncertain, levels of electrical demand.

There are many more factors to consider in minimizing costs and providing economic and reliable electric power to end-use customers than was the case in the past. Demands on the industry to take greater recognition of the environment, non-utility generation, trade opportunities and management of demand are but a few factors that have added to the complexity of electric utility planning. The task seems destined to become no easier in the 1990s.

In some cases, as many of these demands have gone beyond the expertise housed within the utilities, the response has been conservative so as not to compromise existing customer service levels. However, Canada's electric utilities are marshalling their resources to examine the potential and appropriate role of demand-side management, independent power production, and public concern with the environment. Research and demonstration programs (R&D) are underway in some regions and more will be undertaken to ensure that incorporation of these new factors is complimentary to the utilities' least-cost planning practices.

In some areas, utilities' ability to act has also been hampered by outdated regulation. Clear policy statements from provincial and federal authorities are required to ensure that Canada's electric utilities are working in concert with clearly enunciated policy directives. In many cases, formalizing these policy statements will require considerable time and cost. Ontario Hydro's Draft Demand/Supply Strategy and the various responses this has elicited is a good case in point. This examination took over 6 years. The outcome, however, is a better and broader understanding of the whys and wherefores of Ontario's electric power planning.

In many regions, the dictates of ensuring reliable and inexpensive electricity have forced crown-owned utilities to build new, larger generating units without a clear regard for other options which could permit greater flexibility and lower long-term costs. Moreover, the directive of producing one product has often times led utilities to dismiss the importance of competitive products such as natural gas and end-use efficiency products. This mandate has allowed them to remain distant from an understanding of how their customers use

electricity. Many things have changed over the past three decades--so too should legislation governing the utilities.

Electricity trade is yet another area where utilities and their regulators should undertake a fundamental review. Trade may represent the most economic supply option, but is not accorded equal treatment. Regulatory changes at both the provincial and federal level will be required if utilities are to fully take advantage of the benefits of greater trade between provinces. *Reduced* emission levels and *somewhat lower* electric power rates and would result from more coordinated electric power planning in Canada.

Immediate R&D on the environment and the appropriate utility response is also called for. Again the *proper context* must be set by federal and provincial policy guidelines which account for the implications of changes in emission levels on the industry and its customers. *Equally* important are equity considerations. For example, controlling electric utility emissions must be assessed in a broad context where consideration is given to the most cost-effective means of reducing emissions from all sources--both energy and non-energy sectors of the economy (e.g., agriculture and forestry).

Government and utility R&D must also be set in the right context. Global environmental problems, for example, may require consideration of cost-effective solutions that go beyond what Canada itself can do to limit emissions. Global problems sponsor complex questions and tradeoffs. How, for example, should priorities be set for funding to reduce harmful environment emissions--what allocation of funds should go to (i) energy efficiency programs versus (ii) clean coal technologies versus (iii) demand-side management versus (iv) independent power production versus (v) forest fire prevention versus (vi) aid for energy efficiency and reforestation in developing countries? The uncertainties regarding costs, implementation, customer acceptance, and context (regional, national and international) add layers of complexity to an important and complicated problem. These factors also underscore the importance of the question and the exploration of answers and timely remedies as the analysis of the best means of reducing greenhouse gases will require considerable time if the analysis is to be done correctly.

7.4 Recommendations

Many of the issues discussed in the report will be important points of departure for research, development & demonstration

(R, D&D) by Canadian utilities in the forthcoming decades. However, some of these issues are of more immediate importance, particularly to utilities under pressure to bring on new generating capacity. Consequently, the priority of research initiatives will differ on a region-specific basis.

- General policy: encourage energy efficiency in the production and use of electricity in all sectors of the economy to encourage overall productivity performance and reduce environmental impacts.

7.4.1 Electricity Trade

A thorough assessment should be undertaken immediately of ways to enhance interprovincial electricity trade and greater cooperation between utilities in systems planning and development. This assessment should recognize greater electricity trade as a least-cost energy strategy. The National Energy Board and Environment Canada in consultation with the electric utilities should jointly review means of promoting greater interprovincial power planning so as to minimize environmental impacts. Greater public understanding of the costs and benefits of greater electricity trade is fundamental, e.g., the question of potential health effects of high voltage transmission lines must be answered and publicly made known.

7.4.2 Non-Utility Generation

Non-utility generation should, *where practical*, be actively supported. The potential of this supply alternative should be evaluated in the context of a comprehensive review of current U.S. state practices and FERC initiatives on avoided cost and competitive bidding program structures. Cogeneration and utility/industry partnerships should be encouraged by regulators. The Canadian Electrical Association is an appropriate body to direct this research.

7.4.3 Demand-Side Management

To reduce current uncertainty about the cost and effectiveness of demand-side strategies, an assessment should be undertaken of the different modelling techniques available and under use by various electric utilities in the United States and abroad. To account for a more comprehensive analysis of programs and factors which may come into play in the future, it would make considerable sense that this assessment be broadened to consider the availability and usefulness of least-cost planning models to utilities in Canada. Work done by the Electric Power Research Institute, the Edison Electric Research

Institute, the Northwest Power Planning Council, the National Regulatory Research Institute, Central Maine Power and the Bonneville Power Administration would be good starting points in this endeavour.

Competitive bidding programs under development in the United States should also be examined for their applicability to Canada. The Canadian Electrical Association seems an appropriate entity to undertake a survey of competitive bidding practices (demand- and supply-side) in the United States and evaluate the practicality of the various programs to Canada's electric utilities.

7.4.4 Environment

Environmental concerns are at the forefront of issues facing Canada's electric utilities and the drive to increase efficiency in production and electricity end-use. Significant R&D is required to evaluate flue gas desulphurization, fluidized bed combustion, integrated coal gasification combined cycle, advanced combustion technologies, coal beneficiation, sorbent injection and increased efficiency of existing generating units.

Environmental concerns point to an evaluation of alternative "environmentally friendly" sources of supply such as non-utility generation, greater electricity trade, demand-side management, and a shift to lower carbon fuels such as natural gas and small hydro. Government should do more, not less, to accelerate these trends. R&D program budgets should be *increased*, not reduced, particularly at a point in time where energy prices are low. When energy prices are high, it's already too late to undertake fundamental, pro-active R&D.

- Establish objective criteria to determine full environmental cost of all existing fuel sources, alternative fuels and technologies.
- Investigate the least-cost options for meeting national and international protocols in energy and non-energy sectors of the economy.
- Review national energy policy in light of changing energy-economy-environmental conditions, the growing role of electricity, and long-term national and regional objectives.
- Advance the development and commercialization of clean coal technologies.

- Evaluate federally-directed research and development and foreign aid in a context which examines all of Canada's least-cost options for meeting international environmental protocols.
- Examine and evaluate policy options for implementation of environmental goals. The distortive effects of such policy tools on energy markets and the distribution of associated costs across all the players involved must be assessed and clearly understood prior to selection of an optimal policy instrument.
- Examine CO₂ sinks, such as reforestation.
- Investigate the costs and regional and national economic impacts of changes in environmental regulations.

In order to minimize uncertainty and its impact on utility planning, government should:

- support research directed to evaluate the environmental implications of human activities, especially in the energy sector;
- collect information on the course of government and industry response in other countries and make the Canadian position known through participation in international forums on the environment;
- provide information to the Canadian public so that attitudes and decisions can be formed on the basis of the best information available; and
- continue to work on all facets of the environmental problem with all the major stakeholders; or
- establish objective criteria to judge the full environmental cost of each fuel source and assess alternative fuels and technologies.
- examine the most appropriate policy options for remedying environmental externalities.⁴

As SO₂, NO_x, VOCs, and CO₂ emissions all result from the combustion of fossil fuels, it is imperative that an examination be made of all sources of emissions at the same time, so that time and money are not needlessly spent discussing controls for one which are later made redundant by controls for another. A comprehensive approach, not a band-aid approach, is required if public funds are to be spent wisely in managing Canada's economy-environment interactions.

More research and consultation must attend future government initiatives. Canadians need balanced and intelligently planned environmental initiatives which do not cause unnecessary harm to our economic and employment base.⁵

In this *broader context*, Canada should examine means of increasing the average fuel efficiency of its transportation network as this sector is largely responsible for NO_x and CO₂ emissions. The relative effectiveness of market-based incentives and mandates must also be examined for all sectors to ensure the most appropriate, cost-effective outcome.

Footnotes

¹Depending on how quickly regulatory organizations act in tandem.

²"There is fairly widespread belief that reliance on competitive bidding for new electric power supplies could, depending on the details of the bidding process, cause a shift in the size of new plants and in fuel choices. If small supply increments, lower short-term costs, and shorter lead time projects are favored, it is likely that more oil and gas generators will be built. However, developing coal technologies--particularly atmospheric fluidized bed and integrated, combined-cycle coal gasification--that are targeted at smaller, modular units could eventually be competitive for cogeneration and utility applications." See U.S. Congress, Office of Technology Assessment, Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition, OTA-E-409 (Washington, D.C.: U.S. Government Printing Office, May 1989), p. 216.

³For a comprehensive, and largely non-technical discussion of strategies to reduce CO₂ see E. J. Wiggins and W. J. Yurko, The Greenhouse Effect and the Alberta Fossil-Fuels Industry (Edmonton, Alberta: AOSTRA), July 31, 1989.

⁴The Canadian Energy Research Institute is undertaking two studies in this area: (1) Environmental Goals and Energy Markets: The Impact of Alternative Policy Options; and (2) The Role of New Coal Technologies in Meeting Canada's Environmental Goals in the Electric Power Sector.

⁵Calgary Chamber of Commerce, "Environment and the Emerging Political Agenda," revised September 1989 submission to the Canadian Chamber of Commerce (Calgary, Alberta: Calgary Chamber of Commerce, September 1989), p. 4.

GLOSSARY

These definitions are taken from the House of Commons report, Nuclear Energy: Unmasking the Mystery, August 1988; World Resources Institute and International Institute for Environmental and Development, World Resources 1988-89; Energy, Mines and Resources Canada, Electric Power in Canada 1988; House of Commons report, Report of the Special Committee on Acid Rain; and U.S. Congress, Office of Technology Assessment, Electric Power: Wheeling and Dealing.

ACID: A concentration of hydrogen ions (H^+) in solution. Acidity is expressed on a numerical pH scale. An acidic solution has a pH less than 7.0.

ACID RAIN: A general term describing precipitation in any form that has been acidified by the presence of atmospheric pollutants, primarily the oxides of sulphur and nitrogen.

ACID RAIN PRECURSOR: A material such as SO_2 or NO_x which is transformed in the atmosphere to become a component of acid rain.

AEROSOL: A suspension of liquid or solid particles in a gas.

ALKALINITY: A measure of water's ability to neutralize added acids by the reaction of hydrogen ions with carbonate, bicarbonate, and hydroxide ions.

ALTERNATING CURRENT: An electric current that flows alternately in one direction and then in the reverse direction. In North America, the standard for alternating current is 60 complete cycles per second; such electricity is said to have a frequency of 60 hertz. Alternating current is used in almost all aspects of power systems because it can be transmitted and distributed much more economically than direct current.

ALTERNATIVE ENERGY/TECHNOLOGY: Energy sources or technologies which are not yet widely used, as opposed to "conventional" energy/technology. The term usually refers to renewable energy sources and small, decentralized installations. Examples are photovoltaics, solar heating, wind power and waste-fuelled electrical generation.

ARTIFICIALLY-FIXED NITROGEN: Traditional farmers intervene in the nitrogen cycle by cultivating legumes interspersed with other crops, or in rotation with them, plowing legumes under as green manure and by recycling biomass such as

crop residues and animal and human wastes. Modern agriculture retains some of these practices, but the total mass of recycled organic nitrogen is now dwarfed by industrial production of nitrogen fertilizers from atmospheric nitrogen. Synthetic ammonia production has grown exponentially since its commercialization in the early 1920s. Worldwide output is now 90 million metric tons of nitrogen, with 80 percent used as fertilizer.

Synthetic ammonia is used directly as a cheap, highly concentrated fertilizer or converted to urea, nitrates, or compound fertilizers (combinations of nitrogen with phosphate, potassium, and micronutrient elements).

When excess nitrogen fertilizer is applied to a field the levels of nitrate in the runoff and nitrous oxide in the atmosphere increase. Nitrous oxide levels are enhanced because nitrification and denitrification, which convert nitrogen fertilizers and biomass to nitrous oxide and then to nitrogen gas, sometimes stops with the production of nitrous oxide. When farmers fertilize or over-fertilize crops with synthetic nitrogen fertilizers produced from nitrogen gas, they essentially withdraw nitrogen from the atmosphere in its stable molecular form and return some of it as nitrous oxide, a compound that has important environmental impacts.

ASSURED SYSTEM CAPACITY: The dependable power-generating capacity of system facilities available for serving system load after making provision for required reserve generation, including the effects of agreements with other systems.

ASYNCHRONOUS TIE: A direct-current interconnection between two alternating-current systems, so-called because the two systems need not be in synchronism with each other.

AVERAGE ENERGY: The energy which would be generated by the hydroelectric stations in a river system under average streamflow conditions.

AVERAGE STREAMFLOW: The arithmetic average of all recorded flows in a river over a specified period of time, usually measured on an annual basis.

AVOIDED COST: The cost which would be incurred by an electric utility in providing new generating capacity if the utility were to provide the power itself instead of purchasing it from an independent generator.

BASE: The opposite of acid; depends on the concentration of hydroxyl ions (OH^-) in solution. A basic alkaline solution has a pH greater than 7.0.

BASE LOAD: The minimum continuous load over a given period of time.

BASE-LOAD GENERATING STATION: A generating station which is normally operated to supply all or part of the base load of a system and which consequently operates at full output whenever available. Base-load generating units tend to be large units with low operating costs.

BUFFER: A chemical which, in solution, will resist changes in pH or, if added to a solution, will change the pH of that solution. In nature, limestone (calcium carbonate) will act as a buffer against acid rain to maintain or raise the pH of a waterbody.

BULK ELECTRICITY SYSTEM: The generation and high voltage transmission facilities (generally 115 kilovolts and up) considered as a whole.

BUS: A set of electrical conductors that serves as a common connection for two or more circuits. A bus may be in the form of rigid bars ("busbars") or in the form of cables.

CARBON DIOXIDE: Emissions caused by natural and human factors. Volcanoes emit carbon dioxide, and major changes in global vegetation can contribute to, or withdraw from, the atmospheric carbon reservoir. Combustion of fossil fuels adds carbon to the atmosphere, as do gas flaring and cement production. In addition, carbon is released by the burning or decomposition of the biomass when forestland is cleared.

CAPABILITY: The maximum load that a station or equipment is capable of carrying under specified conditions.

CAPACITY: The rate of delivery of energy (for example, a utility might sell 50 megawatts of capacity or electric power) or the maximum quantity of power that a piece of equipment or a system is capable of carrying or supplying (for example, a generating unit might have a rated capacity of 50 megawatts).

CAPACITY FACTOR: For any equipment, the ratio of the average load during some period of time to the rated capacity of the equipment. Capacity is usually expressed as a percentage.

CHLOROFLUOROCARBONS: Chlorofluorocarbons (CFCs), in the form of CFC-11, CFC-12, and CFC-113, affect the climate through their absorption of infrared radiation and their reaction in the atmosphere with other chemicals. The CFCs produce a highly reactive form of chlorine, which in turn depletes the stratospheric ozone layer. In Canada, almost 70 percent of CFCs are used in air conditioning and rigid foam insulation.

On July 1, 1989, Environment Canada introduced regulations that will reduce the use of CFCs in Canada to 50 percent of their 1986 levels by 1999. In light of recent information regarding the impact of CFCs on the ozone layer,

further reductions may be required. In February 1989, Ontario announced that its Environmental Protection Act will be amended to eliminate the manufacture and use of CFCs.

CIRCUIT: Any conductor or set of conductors intended to carry electricity.

CIRCUIT BREAKER: A switching device to open or close an electric power circuit during either normal system operation or fault conditions.

COGENERATION: The combined production of electricity and useful heat (usually steam).

CONSUMPTION: Use of electrical energy, typically measured in kilowatt-hours.

CONTROL CENTRE: The control room from which instructions are issued for switching of power system equipment, stations or lines, and for changing the amount of power generated in power stations. Typically such a centre is equipped with remote controls, telemetering and computer facilities. Automated system maps indicate the operating status of generating units, transmission lines and main substation equipment. Metering devices show the loads being carried by units and lines, and the voltage levels at selected locations. Thus the system supervisor is provided with a complete picture of the main features of the power system and can coordinate its operations.

CONVENTIONAL GENERATION: Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels.

CONVERTER STATION: An installation for converting direct current into alternating current, or for changing one frequency of alternating current to another.

CURRENT: The flow of electricity in a conductor. Current is measured in amperes.

DEMAND: The desire of purchasers for electricity. "Demand" is often used synonymously with "power" which is the rate at which electrical energy is being delivered.

DEMAND CHARGE: The component of a two-part price for electricity which is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used. The other component of the two-part price is the energy charge.

DEMAND MANAGEMENT: Actions taken by a utility or other agency intended to influence the amount or timing of customers' use of electricity.

DEPENDABLE CAPACITY: The load-carrying ability of a station or system under adverse conditions, as for example, the capacity of a hydroelectric station under defined low-flow conditions.

DIRECT CURRENT: Current that flows continuously in one direction (as opposed to an alternating current). The current supplied from a battery is direct current.

DIRECT CURRENT TRANSMISSION: Transmission of electricity by direct current instead of the usual alternating current. Direct current has certain advantages for long-distance, point-to-point transmission and for interconnecting power systems that would otherwise be unstable if an attempt were made to tie them together by alternating current transmission. There are four high-voltage dc installations in service in Canada: (1) the Vancouver Island underwater transmission link; (2) the Nelson River (Manitoba) overhead transmission line; (3) the Eel River (New Brunswick) asynchronous tie; and (4) the Chateaugay (Quebec) asynchronous tie.

DISTRIBUTION SYSTEM: The lines, transformers, switches, etc. used to distribute electricity over short distances from the transmission system to customers. Distribution generally takes place at relatively low voltages (44 kilovolts and less).

DRY DEPOSITION: A process whereby particles such as fly ash, sulphates and nitrates, and gases such as sulphur dioxide and nitric oxide are deposited on, or absorbed onto, surfaces. The dry particles or gases can be converted into acids after deposition when they contact water.

ECONOMIC DISPATCH: A system for selecting generating units to operate to balance supply and demand at minimum cost.

ECONOMY ENERGY: Energy sold by one power system to another to effect a saving in the cost of generation when the receiving utility has adequate capability to supply the loads on its own system.

ELECTRICAL POWER: The rate of delivery of electrical energy and the most frequently used measure of capacity. The basic unit is the kilowatt (kW).

ELECTRICAL UTILITY: An organization that has as its prime purpose the generation, transmission and/or distribution of electric energy for sale.

ELECTRO-TECHNOLOGY: A technology that uses electricity in its processes, especially new technologies used to displace other energy sources. An example is the use of electrically-driven heat pumps for kiln drying wood, in place of air heated by on-site fuel combustion.

ENERGY CHARGE: The component of a two-part price for electricity that is based on the amount of energy taken. The other component of price is the demand charge.

ENERGY SOURCE: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

EXTRA HIGH VOLTAGE (EHV): Any transmission voltage higher than those commonly used. The utility industry has generally considered EHV to be 345 kilovolts (kV) or higher, although such voltages are becoming increasingly common.

FIRM ENERGY OR POWER: Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

FLUIDIZED-BED COMBUSTION: A method of combustion in which air, blown up through orifices in the floor of the firebox, suspends particles as a fluidized bed. The particles consist of fuel and a sorbent such as limestone.

FORCED OUTAGE RATE: The probability that a particular generating unit or other system component will be unavailable for service because of breakdown.

FREQUENCY: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

FUEL REPLACEMENT ENERGY: Energy sold by one utility to another to enable the purchaser to avoid burning fuel in its own thermal generating facilities. Fuel replacement energy is typically priced at a percentage of the fuel cost avoided by the purchasing utility.

GENERATING STATION: A station comprising one or more generating units for the production of electricity. The main types of generating stations are hydroelectric, nuclear-electric and fossil-fuelled (by coal, oil or natural gas). In some parts of the world, such as the Geysers region of California, geothermal-electric power is becoming an important element of generating capacity.

GENERATING UNIT: An electric generator, the prime mover that drives the generator, and all the associated equipment that must be operated together as a group to generate electricity. A generating unit can usually operate independently of other units at a multi-unit station.

GENERATION REJECTION: Disconnecting selected generating units from a power system to preserve the continuing safe operating of the rest of the system. This action is sometimes

taken if a large block of load has suddenly been cut off by some emergency, leaving generators feeding into the system without enough connected load to absorb their output. The units would otherwise overspeed, raising the frequency and voltage on the system to unacceptable levels.

GIGAWATT (GW): One billion watts. (See Watt.)

GIGAWATT HOUR (GW.h): A unit of bulk energy. A million kilowatt-hours. A billion watt hours.

GRID: A network of electric power lines and connections.

GROSS DOMESTIC PRODUCT (GDP): The total value of goods and services produced in Canada. GDP measured in constant dollars is defined as Real GDP.

GROSS NATIONAL PRODUCT (GNP): The total value of production of goods and services measured at market prices.

HEAD (HYDRAULIC): The difference in elevation between the water level immediately above a hydroelectric generating station and the water level immediately below it. The power output of the station is proportional to the hydraulic head.

HEAT RATE: A measure of generating station thermal efficiency, generally expressed as British thermal units per net kilowatt-hour. It is computed by dividing the total heat (Btu) content of the fuel burned by the resulting net kilowatt-hours of electricity generated. In metric units, the heat rate is expressed as kilojoules per kilowatt-hour.

HERTZ (HZ): The units of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 hertz.

HIGH TENSION: Any voltage in excess of 750 volts.

HYDROELECTRIC STATION: An electric generating station in which the prime movers are hydraulic turbines.

INCREMENTAL GENERATING COST: The cost of generating one additional unit of electric energy above some previously determined base quantity.

INDEPENDENT (PRIVATE) GENERATION: Generation owned or operated by producers other than a utility. These producers usually have generating plants for the purpose of supplying electric power required in their own industrial and commercial operations. The term also covers private plants whose sole purpose is the sale of electricity to a utility.

INSTALLED (GENERATING) CAPACITY: The capacity measured at the output terminals of all the generating units in a station, before deduction of station service requirements.

INTEGRATED PLANNING: Joint planning by different power systems in order to minimize total costs. Integrated planning is one characteristic of a true power pool.

INTERCONNECTION AGREEMENT: An agreement made between two power utilities to govern the operation of interconnections between their systems. Typically such an agreement defines different classes of inter-utility electricity transfers and specifies how they shall be priced between the two companies.

INTERCONNECTED SYSTEM: A system consisting of two or more individual power systems connected together by tie lines.

INTERRUPTIBLE ENERGY OR POWER: Energy or power made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

INTER-UTILITY TRANSFER: A transfer of electric power between two or more electrical utilities. The NEB Part VI Regulations define five classes of inter-utility transfer. These are:

- (1) **Adjustment transfer:** A transfer of electric power or energy made: (a) to adjust an energy account balance; (b) to compensate for electrical losses; (c) to compensate for services rendered; (d) to deliver output entitlements; or (e) to provide upstream or downstream benefits.
- (2) **Carrier transfer:** A transfer of electric power or energy by one utility over the circuits of another, for delivery either to a third party or back to the originating utility.
- (3) **Equichange transfer:** An interchange of equal quantities of electric power or energy within a stated period.
- (4) **Sale transfer:** A transfer of electric power or energy under a contract of sale.
- (5) **Storage transfer:** An electric energy transfer "banked" for the time being in the form of water in the reservoir space of another electrical utility, in the expectation that equivalent electric energy will be returned at a later time.

ISOLATED SYSTEM: An electric power system not interconnected with any other system (such as the Northern Canada Power Commission). Isolated systems are usually of relatively small capacity.

JOULE: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt-hour.

KILOVOLT (kV): 1000 volts.

KILOWATT (kW): The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

KILOWATT-HOUR (kW.h): The commercial unit of electric energy; 1000 watt hours. A kilowatt-hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt-hour is equal to 3.6 million joules.

LEACHING: A natural process by which water dissolves minerals out of rocks. The leaching of heavy metals, such as mercury, into water supplies is believed to be a serious consequence of acid rain.

LICENCE: A licence to export electricity from Canada, issued under Part VI of the National Energy Board Act, following a public hearing. A licence is subject to the approval of the Governor in Council.

LIMESTONE: A sedimentary rock consisting chiefly of calcium carbonate. Limestone is an effective buffer against acid rain.

LOAD: The amount of electric power or energy consumed by a particular customer or group of customers.

LOAD CURVE (SHAPE): The pattern of electricity use or production when demand is plotted against time.

LOAD FACTOR: The ratio of the average load during a designated period to the peak or maximum load in that same period, usually expressed as a percentage of the peak load.

LOAD MANAGEMENT: The manipulation of customer demand by economic and/or technical means.

LOAD REJECTION (LOAD SHEDDING): Interrupting the supply of electricity to a selected region or group of customers as a means of preserving the continuing safe operation of the remainder of a power system. This action is sometimes taken in an emergency when the total system load exceeds the capacity of the generation available to supply it.

LOAD SHIFTING: Shifting electrical demand from one period to another, usually from high-load to low-load periods.

LOCKED-IN ENERGY: Energy production capability at a generating station which cannot be used because of inadequate

transmission capability connecting the generating station to the load. For example, part of the generating capacity of the Bruce Nuclear Generating Station is locked in.

LOOP FLOWS: Parallel path flows crossing utilities' boundaries along paths not contracted for or scheduled.

LOSSES: Energy or power lost in circuits or equipment, mainly in the form of heat, when current flows through the circuit.

MARGINAL COST: The cost of supplying an additional unit of output. When the extra unit of output can be supplied simply by increasing production from the existing plant, it is usually specified at the "short-run marginal cost" or "incremental cost;" when new plant is required to supply the additional production, it is usually termed the "long-run marginal cost."

MARGINAL COST PRICING: A rate structure in which prices are set at the cost of the last (marginal) unit of production, rather than at cost of production averaged over all output.

MEGAWATT (MW): a unit of bulk power; 1000 kilowatts.

MEGAWATT HOUR (MW.h): A unit of bulk energy; 1000 kilowatt-hours.

METHANE (CH₄): After carbon dioxide, methane is the second largest contributor to the greenhouse effect. Most methane emissions are generated by natural sources such as decomposition of materials in wetlands and by non-energy-related human activities such as agriculture and animal husbandry. The production and use of energy account for only a limited share of methane emissions.

MILL: 1/1000 of a dollar.

MOTHBALL: To take equipment that is surplus to current needs or that has reached the end of its normal life and retain it in a preserved state. Mothballed equipment is not available for immediate use but can, with preparation, be resurrected for future use.

NAME-PLATE RATING: The full-load continuous rating of a generator or other electrical equipment under the conditions designated by the manufacturer, as indicated on the name plate attached to the device.

NATIONAL AMBIENT AIR QUALITY OBJECTIVES: Prescribed by the federal government under the *Canadian Environmental Protection Act* to reflect regional air quality goals in three ranges--"tolerable," "acceptable," and "desirable." They are not source-specific but are geographical area-specific. They are applicable to specific air contaminants. They are

enforceable by the provinces once adopted by them as part of their environmental laws in virtue of a federal-provincial agreement under the federal *Canadian Environmental Protection Act*.

NITROUS OXIDE (N_2O): Combustion of fossil fuels releases nitrous oxide, which affects the formation of ozone in the troposphere. Data are not available on levels of nitrous oxide emissions from the combustion of different fossil fuels. The non-energy sources of nitrous oxide emissions such as the use of agricultural fertilizers are believed to be far larger than the energy-related sources. About one-third of total global N_2O emissions are anthropogenic, resulting mainly from fertilizer application and to a lesser extent from large stationary combustion sources. Mobile sources are not significant emitters of N_2O .

NONFERROUS SMELTING: The smelting, roasting, and sintering of sulphur-containing ores, such as those containing copper or nickel, and scrap materials.

NUCLEAR FUEL: A substance containing one or more fissile nuclides capable of maintaining a chain reaction in a reactor. The term may also be used to include a substance containing one or more fertile nuclides that can be transmuted into such fissile nuclides.

NUCLEAR POWER: Power generated at a station where the steam to drive the turbines is produced by the process of atomic fission, rather than by burning a combustible fuel.

NUCLEAR (FISSION) REACTOR: A device in which a self-sustaining nuclear fission chain reaction can be maintained and controlled. The term "nuclear reactor" is sometimes applied to a device in which a nuclear fusion reaction can be produced and controlled (fusion reactor).

NUCLIDE: An individual atomic species. Deuterium and tritium, although they are both isotopes of hydrogen, are two different nuclides.

OUTAGE: The state of any circuit component when it is not available to perform its intended function because of some event associated with that component. An outage may or may not cause an interruption of service to customers, depending on the layout of the system.

PARALLEL POWER: Independent generation which is linked to and synchronized with the bulk electricity system.

PEAK DEMAND: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or, more usually, the average

load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

PEAK PERIOD: Periods during which relatively high demands are placed on an electrical system, as opposed to off-peak periods.

PEAKING UNIT: A generating unit intended to be operated intermittently to supply peak loads.

pH SCALE: is used to measure acidity or alkalinity. Neutral solutions have a pH of 7, acid solutions have a pH less than 7, and alkaline solutions have a pH greater than 7. Each unit change in pH represents a tenfold change in acidity. For example, rainfall with pH 4 is 10 times as acidic as rainfall with pH 5 and 100 times as acidic as rainfall with pH 6.

POLLUTION RIGHTS: A system of marketable permits allowing the bearer to emit a specified level of pollutants. Under this rights system, the government controls the total level of emissions, but not the distribution of these emissions among firms.

POWER POOL: A grouping of two or more interconnected electric systems planned and operated to supply power in the most reliable and economical manner for their combined load requirements.

POWER REACTOR: A nuclear reactor whose primary purpose is to produce energy. Reactors in this class include electric power reactors, heat-producing reactors (producing heat for industrial processing, to supply district heating systems, etc.) and propulsion reactors in nuclear-powered surface vessels and submarines.

POWER SYSTEM: All the interconnected facilities of an electrical utility. A power system includes the generating stations, transformers, switching stations, transmission lines, substations, distribution lines and circuits to the customers' premises; that is, all the facilities required to provide electrical services to the customers.

PRIMARY ENERGY SOURCE: The source of primary energy from which electricity is generated, including falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, biomass, direct solar radiation, geothermal energy and tidal energy.

PRIME MOVER: The turbine or engine that drives an electrical generator.

PUMPED STORAGE: An arrangement in which water is pumped from a lower to a higher reservoir, during off-peak hours. During peak hours, the water is allowed to return to the

lower reservoir through hydroelectric turbines, thus generating power. Usually the turbines are reversible so that they can also serve as the pumps in the system.

QUALIFYING FACILITY (QF): Generating unit qualifying for special regulatory treatment under the Public Utility Regulatory Policies Act of 1978.

RADIOACTIVE WASTE: Unwanted radioactive materials obtained in the processing, handling or utilization of radioactive substances. Such wastes may be classified according to their degree of activity or to their half-lives, as follows.

A. According to the radionuclide contents:

high-level waste: the highly radioactive liquid separated during the chemical reprocessing of irradiated fuel; or irradiated reactor fuel if it is not foreseen that the spent fuel will be reprocessed; or any other waste with a comparable radioactivity level.

intermediate-level waste: waste of a lower radioactivity level than high-level waste, but which still requires shielding during handling.

low-level waste: waste which does not require shielding during normal handling because of its low radionuclide content.

B. According to the half-life of the radioactive waste:

long-lived waste: waste that will not decay to an acceptable activity level in a period of time during which administrative controls can be expected to last.

short-lived waste: waste which will decay to a level considered to be insignificant from a radiological viewpoint, in a time period during which administrative controls can be expected to last. In some jurisdictions, radionuclides with a half-life of less than 30 years are considered to fall into this category.

RADIOACTIVE WASTE MANAGEMENT: All activities, administrative and operational, that are involved in the handling, treatment, conditioning, transportation, storage and disposal of radioactive waste.

RADIOACTIVITY: The property of certain nuclides of spontaneously emitting particles or gamma radiation from their nucleus, of undergoing spontaneous fission, or of emitting X-radiation.

RELIABILITY: The ongoing ability of a power system to avoid outages and continue to supply electricity with the appropriate frequency and voltage to customers.

RENEWABLE ENERGY SOURCE: A source of energy which is inherently self-renewing, such as the various manifestations of solar energy (water power, biomass, wind energy, direct solar radiation, wave energy and ocean currents), tidal energy and geothermal energy.

RESERVE MARGIN: The difference between generating capacity and peak load, expressed as a percentage of peak load.

RESERVE (GENERATING) CAPACITY: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required for two main reasons: in case of the unexpected breakdown of generating equipment; and in case the actual peak load is higher than forecast.

RETAIL WHEELING: Wheeling for delivery of power to a retail customer.

RIGHT-OF-WAY: The strip of land on which a power line is located, and on which the power company has acquired the legal right to perform construction and maintenance, to restrict the growth of vegetation, and sometimes to restrict construction by other parties. The width of the right-of-way varies with line voltage.

RUN-OF-THE-RIVER PLANT: A hydroelectric generating station having negligible capacity for the storage of water, so that the plant has to run on the natural flow of the river. The output of the plant may therefore be subject to considerable variation.

SCHEDULED MAINTENANCE: Maintenance of equipment performed in accordance with a prearranged schedule.

SEASONAL DIVERSITY: The diversity between loads that reach their maximum values at different seasons of the year. For example, most Canadian power systems experience their annual peak loads in the winter, whereas many U.S. systems have their annual peaks in the summer because of air conditioning. Systems that differ in this way can effect economies of scale by exchanging energy on a seasonal basis.

SERVICE AREA: The area within which a utility is required, or has the right, to serve consumers.

SHORT-TERM POWER: Power and associated energy which one utility purchases from another for the purpose of obtaining a supply of power intended to be available at all times during the period covered by the commitment.

SOCIAL BENEFITS: Benefits, whether tangible or intangible, resulting from a project. Social benefits are distinguishable

from private benefits in that they include all the benefits of a project, whether or not they accrue to project sponsors.

SOCIAL COSTS: Costs or damages, whether tangible or intangible, which a project causes to be imposed. Social costs are distinguishable from private costs in that they include all the costs of a project incurred by all citizens rather than those only incurred by the project sponsors.

SORBENT: An additive used to enhance sulphur dioxide removal, e.g. lime.

SPINNING RESERVE: That portion of the reserve generating capacity which is actually in service, connected to the system, spinning (but not generating full power), and which is ready to pick up load automatically at a moment's notice.

SPLIT SAVINGS: A widely-used formula for the pricing of energy, especially economy energy sold by one utility to another, in which the total saving resulting from a sale is split equally between buyer and seller.

STABILITY: The ability to maintain synchronous operation following disturbance.

STATION SERVICE: The electricity required at a generating station to run the auxiliary plant plus the capacity represented by the losses in the generator transformers.

STORAGE: The water held in a reservoir. Storage is used to even out the natural variations of flow in a river, so that the output of hydroelectric generation can be made as independent as possible of such natural variations.

SUBSTATION: A station at which the voltage of the bulk power system is stepped down to a level suitable for distribution, and at which the feeders at this lower voltage originate and may be switched on or off.

SULPHUR DIOXIDE: A heavy, odourless, suffocating gas with the chemical formula SO_2 . Sulphur dioxide is created by both natural and anthropogenic activities. Anthropogenic sources include fossil fuel combustion and industrial activities. High levels of sulfur dioxide and suspended particulate matter (SPM) may cause respiratory problems among adults and children and may also result in lower respiratory tract illness.

SUMMER PEAK: The highest load on a power system during the summer, usually caused by air conditioning in hot weather.

SUPERCONDUCTOR: An electrical conductor offering negligible resistance to the flow of electricity.

SURPLUS ENERGY: Energy that is surplus to the needs of its owner, including both load and reserve. Surplus energy can be produced whenever the total generating capacity exceeds the total load, and is often sold on an interruptible basis.

SUSPENDED PARTICULATE MATTER (SPM): Levels of SPM rise both from human and natural activities including combustion of wood and fossil fuels, industrial activities, and dust raised by vehicular traffic or wind. High SPM levels may aggravate respiratory illnesses.

SWITCHING STATION: A station at which the transmission lines of a power system can be selectively connected or disconnected by means of switchgear.

SYNCHRONISM: The condition of alternating current generators being "in phase;" that is, timed so that their voltage waves reach the maximum and minimum values at exactly the same instant. This is an essential condition in order for alternating current generators to operate on the same system.

SYNCHRONOUS TIE: Any alternating current tie line. All generating units interconnected by the tie must be in synchronism.

TERAWATT HOURS (TW.h): One billion kilowatt-hours.

THERMAL GENERATING STATION: An electric generating station where the prime movers are driven by gases or steam produced by burning fuels (such as coal, oil, gas, wood or refuse) or by nuclear processes.

THERMAL REACTOR: A reactor in which fission is induced predominantly by thermal or "slow" neutrons.

TIME-OF-USE (TIME-DIFFERENTIATED) RATES: Rates which vary based on the time of day, day of the week, or season of the year.

TON: Also known as a short ton, it contains 2,000 pounds. One ton equals 0.9072 tonne.

TONNE: A metric ton, or tonne, contains 1,000 kilograms, or 2,204.623 pounds. One tonne equals 1.1023 tons.

TRANSFORMER: An electromagnetic device for raising or lowering the voltage of alternating current electricity.

TRANSMISSION LINE: A line used for the transmission of electric power at high voltage. Transmission lines may be constructed overhead, underwater or underground. Lines of voltage less than 115 kilovolts are usually considered to be subtransmission or distribution.

TRANSMISSION SYSTEM: Lines, transformers, switches, etc. used to transport electricity in bulk from sources of supply to other principal parts of the system. Transmission is generally at voltages of 115 kilovolts and above.

TURBINE (HYDRAULIC): A rotary type of prime mover in which mechanical energy is produced by the force of water, steam or gas directed against blades fastened to a rotating shaft.

ULTRA HIGH VOLTAGE (UHV): Any voltage in excess of approximately 1000 kilovolts.

VOLTAGE: The electrical force, measured in volts or multiples of volts (e.g. kilovolts) that causes a current to flow in a circuit. In North America, the standard voltage for residential use is 115 volts, with 230 volts used for heavy appliances such as ranges, dryers and hot water heaters. Voltages used for urban and rural distribution range from about 4 kV to 44 kV. The most common transmission voltages are 115, 132, 230, 345, 500 and 735 kV. The higher the voltage, the more power a transmission line can carry.

WATT: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.

WET DEPOSITION: A process of precipitation whereby acidic chemicals, including dilute sulphuric and nitric acids and sulphates, are deposited in rain, snow, etc.

WHEELING: The transmission of power belonging to one utility through the circuits of another utility, for delivery either to a third party or back to the originating system.

WINTER PEAK: The highest load on a power system during the 6-month period October to March. In Canada, the winter peak almost always occurs in December or January.



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